Case No. PUR-2023-00066
Sponsor: ("DOMINION")
Exhibit No. 2

Witness: NONE
Bailiff: JABARI T. ROBINSON

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May 1, 2023

BY ELECTRONIC DELIVERY

Bernard Logan, Clerk
Document Control Center
State Corporation Commission
1300 E. Main Street, Tyler Bldg., 1st Fl.
Richmond, VA 23219

Commonwealth of Virginia, ex rel. State Corporation Commission,
In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan
filing pursuant to Va. Code § 56-597 et seq.
Case No. PUR-2023-00066

Dear Mr. Logan:

Please find enclosed for electronic filing in the above-captioned proceeding the 2023 Integrated Resource Plan (the "2023 Plan") of Virginia Electric and Power Company (the "Company") filed pursuant to § 56-597 *et seq.* of the Code of Virginia ("Va. Code") and the Integrated Resource Planning Guidelines adopted by the State Corporation Commission of Virginia ("Commission") in Case No. PUE-2008-00099 ("Guidelines"). As required by the Commission, a reference index is enclosed that identifies the sections of the 2023 Plan that comply with the Va. Code, the Guidelines, and the requirements of relevant prior Commission orders. Also enclosed is a copy of the Company's proposed notice in this proceeding pursuant to Section E of the Guidelines.

Along with the 2023 Plan, the Company is filing two addenda under separate cover. Virginia Addendum 1 contains the detailed results of the Virginia consolidated bill analysis, and Virginia Addendum 2 contains the Grid Transformation Plan Document. In addition to the addenda, the Company is contemporaneously filing its Motion for Entry of a Protective Order and Additional Protective Treatment for Extraordinarily Sensitive Information under separate cover where the Company is proposing an additional process for the first time to reduce the administrative burden on the Commission, the Commission Staff, and parties for challenges to confidentiality designations.

Separate from these filings with the Commission, the Company is providing Commission Staff with the Guidelines schedules associated with the 2023 Plan in electronic format pursuant to Section E of the Guidelines, and is providing a copy of the 2023 Plan to members of the General Assembly pursuant to Va. Code § 56-599.

EXHIBIT# 2

To the extent the Commission modifies Rule 260 of the Rules of Practice and Procedure, 5 VAC 5-20-260, in its procedural order for this proceeding related to the deadline to respond to discovery requests, the Company respectfully requests that the Commission allow the Company, Staff, and all respondents at least five (5) *business* days to respond or object to interrogatories or requests for production of documents after the receipt of same. Requiring the response time to be in *business* days instead of *calendar* days allows for intervening weekends and holidays to not be counted and allows the Company and parties time for more fulsome and complete responses. Granting this request will not prejudice Staff or any party in this proceeding and will allow sufficient time to respond to what the Company expects to be a significant amount of discovery over the next several months.

Please do not hesitate to contact me if you have any questions regarding this filing.

Very truly yours,

/s/ Vishwa B. Link

Vishwa B. Link

Enclosures

cc: William H. Chambliss, Esq.
K. Beth Clowers, Esq.
C. Meade Browder, Jr., Esq.
Paul E. Pfeffer, Esq.
Lisa R. Crabtree, Esq.
Mary Lynne Grigg, Esq.
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Nicole M. Allaband, Esq.

Citation	Requirement	2023 Plan Section
Va. Code § 56-598 (1)	An IRP should: 1. Integrate, over the planning period, the electric utility's forecast of demand for electric generation supply with recommended plans to meet that forecasted demand and assure adequate and sufficient reliability of service, including, but not limited to: a. Generating electricity from generation facilities that it currently operates or intends to construct or purchase; b. Purchasing electricity from affiliates and third parties; and c. Reducing load growth and peak demand growth through cost-effective demand reduction programs.	Section 2.2 Alternative Plans
Va. Code § 56-598 (2)	An IRP should: 2. Identify a portfolio of electric generation supply resources, including purchased and self-generated electric power, that: a. Consistent with § 56-585.1, is most likely to provide the electric generation supply needed to meet the forecasted demand, net of any reductions from demand side programs, so that the utility will continue to provide reliable service at reasonable prices over the long term; and b. Will consider low cost energy/capacity available from short-term or spot market transactions, consistent with a reasonable assessment of risk with respect to both price and generation supply availability over the term of the plan.	Section 2.2 Alternative Plans Section 5.5.3 Third-Party Market Alternatives
Va. Code § 56-598 (3)	An IRP should: 3. Reflect a diversity of electric generation supply and cost-effective demand reduction contracts and services so as to reduce the risks associated with an over-reliance on any particular fuel or type of generation demand and supply resources and be consistent with the Commonwealth's energy policies as set forth in § 67-102.	Section 2.2 Alternative Plans
Va. Code § 56-598 (4)	An IRP should: 4. Include such additional information as the Commission requests pertaining to how the electric utility intends to meets its obligation to provide electric generation service for use by its retail customers over the planning period.	2023 Plan Reference Index
Va. Code § 56-599 (A)	Each electric utility shall file an updated integrated resource plan by July 1, 2015. Thereafter, each electric utility shall file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a triennial review filing. A copy of each integrated resource plan shall be provided to the Chairmen of the House and Senate Committees on Commerce and Labor and to the Chairman of the Commission on Electric Utility Regulation.	2023 Plan
Va. Code § 56-599 (A)	All updated integrated resource plans shall comply with the provisions of any relevant order of the Commission establishing guidelines for the format and contents of updated and revised integrated resource plans. Each integrated resource plan shall consider options for maintaining and enhancing rate stability, energy independence, economic development including retention and expansion of energy-intensive industries, and service reliability.	2023 Plan Reference Index
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 1. Entering into short-term and long-term electric power purchase contracts.	Section 2.2 Alternative Plans Section 5.5 Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 2. Owning and operating electric power generation facilities.	Section 2.2 Alternative Plans Section 5.5 Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 3. Building new generation facilities.	Section 2.2 Alternative Plans Section 5.5 Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 4. Relying on purchases from the short term or spot markets.	Section 2.2 Alternative Plans Section 5.5 Future Supply-Side Generation Resources
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 5. Making investments in demand side resources, including energy efficiency and demand side management services;	Section 2.2 Alternative Plans Chapter 6 Generation - Demand-Side Management
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;	Section 2.2 Alternative Plans
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;	Section 2.2 Alternative Plans
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;	Section 1.2 Significant Federal Legislation Section 1.10 Other Legislative Developments Section 5.2.3 Environmental Regulations
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 9. The most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations;	Section 2.4 NPV Results Section 2.6 Sensitivity Analyses
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects; and	Chapter 8 Distribution Appendix 8A 2023 IDP Roadmap Va. Addendum 2 GT Plan Document

Citation	Requirement	2023 Plan Section
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity.	Chapter 6 Generation - Demand-Side Management
Va. Code § 56-599 (B)	In preparing an integrated resource plan, each electric utility shall systematically evaluate, and may propose: 12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation	Section 4.8 Storage-Related Assumptions Section 5.5.1 Supply-Side Resource Options Section 8.5 Battery Storage Pilot Program
Va. Code § 56-599 (C)	As part of preparing any integrated resource plan pursuant to this section, each utility shall conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and shall include the study results in its integrated resource plan. Upon filing the integrated resource plan with the Commission, the utility shall contemporaneously disclose the study results to each planning district commission, county board of supervisors, and city and town council where such electric generation unit is located, the Department of Mines, Minerals and Energy, the Department of Housing and Community Development, the Virginia Employment Commission, and the Virginia Council on Environmental Justice. The disclosure shall include (i) the driving factors of the decision to retire and (ii) the anticipated retirement year of any electric generation unit included in the plan. Any electric generating facility with an anticipated retirement date that meets the criteria of § 45.1-394.1 shall comply with the public disclosure requirements therein.	Not Applicable
Chapter 296 Enactment Clause 12	That any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall consider in its integrated resource plan next filed after July 1, 2018, either as a demand-side energy efficiency measure or a supply-side generation alternative, whether the construction or purchase of one or more generation facilities with at least one megawatt of generating capacity, having a measurable aggregate rated capacity of 200 megawatts by 2024, that use combined heat and power or waste heat to power and are located in the Commonwealth, are in the customer interest. For purposes of this analysis, the total efficiency, including the use of thermal energy, for eligible combined heat and power facilities must meet or exceed 65 percent (Lower Heating Value). The assumed efficiency of waste heat to power systems that do not burn any supplemental fuel and use only waste heat as a fuel source is 100 percent. As used in this enactment, "waste heat to power" means a system that generates electricity through the recovery of a qualified waste heat resource and "qualified waste heat resource" means (i) exhaust heat or flared gas from an industrial process that does not have, as its primary purpose, the production of electricity and (ii) a pressure drop in any gas for an industrial or commercial process.	Section 5.5.1 Supply-Side Resource Options
Chapter 296 Enactment Clause 18	That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity. Considerations shall include analysis of the following: energy efficiency programs for low-income customers in alignment with billing and credit practices; energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions; programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers; options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers; the extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states and an analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and other issues as may seem appropriate.	Section 6.6 GTSA Energy Efficiency Analysis Appendix 6N DNV National Comparison Analysis
Guideline (A)	In order to understand the basis for the utility's plan, the IRP filing shall include a narrative summary detailing the underlying assumptions reflected in its forecast as further described in the guidelines. To better follow the utility's planning process, the narrative shall include a description of the utility's rationale for the selection of any particular generation addition or demand-side management program to fulfill its forecasted need. Such description should include the utility's evaluation of its purchase options and cost/benefit analyses for each resource option to confirm and justify each resource option it has chosen. Such narrative sha l also describe the planning process including timelines and appropriate reviews and/or approvals of the utility's plan. For members of PJM Interconnection, LLC ("PJM"), the narrative should describe how the IRP incorporates the PJM planning and implementation processes and how it will satisfy PJM load obligations.	Chapter 4 Generation Planning Assumptions
Guideline (A)	These guidelines also include sample schedules to supplement this narrative discussion and assist the utilities in developing a tabulation of the utility's forecast for at least a 15-year period and identify the projected supply-side or demand-side resource additions and solutions to adequately and reliably meet the electricity needs of the Commonwealth. This tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the same period. These guidelines also direct that all IRP filings include information to comparably evaluate various supply-side technologies and demand-side programs and technologies on an equivalent basis as more fully described below in Section F(7).	See References for Guideline (F)(7) and Schedules
Guideline (C)(1)	1. Forecast. A three-year historical record and a 15-year forecast of the utility's native load requirements, the utility's PJM load obligations if appropriate, and other system capacity or firm energy obligations for each peak season along with the supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced.	Section 2.2 Alternative Plans Section 4.1 Load Forecast Appendix 2A Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E Appendix 4H Projected Summer & Winter Peak Load & Energy Forecast for Plan B Appendix 4I Required Reserve Margin for Plan B

Citation	Requirement	2023 Plan Section
Guideline (C)(2)	2. Option analyses. A comprehensive analysis of all existing and new resource options (supply- and demand-side), including costs, benefits, risks, uncertainties, reliability, and customer acceptance where appropriate, considered and chosen by the utility for satisfaction of native load requirements and other system obligations necessary to provide reliable electric utility service, at the lowest reasonable cost, over the planning period.	Section 5.5 Future Supply-Side Generation Section 6.7 Overall DSM Assessment
Guideline (C)(2)(a)	a. Purchased Power - assess the potential costs and benefits of purchasing power from wholesale power suppliers and power marketers to supply it with needed capacity and describe in detail any decision to purchase electricity from the wholesale power market.	Section 4.2 Capacity Market Assumptions
Guideline (C)(2)(b)	b. Supply-side Energy Resources - assess the potential costs and benefits of reasonably available traditional and alternative supply-side energy resource options, including, but not limited to technologies such as, nuclear, pulverized coal, clean coal, circulating fluidized bed, wood, combined cycle, integrated gas fication combined cycle, and combustion turbine, as well as renewable energy resources such as those derived from sunlight, wind, falling water, sustainable biomass, energy from waste, municipal solid waste, wave motion, tides, and geothermal power.	Section 5.5 Future Supply-Side Generation
Guideline (C)(2)(c)	c. Demand-side Options - assess the potential costs and benefits of programs that promote demand-side management. For purposes of these guidelines, peak reduction and demand response programs and energy efficiency and conservation programs will collectively be referred to as demand-side options.	Chapter 6 Generation - Demand-Side Management
Guideline (C)(2)(d)	d. Evaluation of Resource Options - analyze potential resource options and combinations of resource options to serve system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction or implementation costs, transmission and distribution costs, environmental impacts and compliance costs.	Section 2.2 Alternative Plans Section 2.6 Sensitivity Analyses
Guideline (C)(3)	3. Data availability. To the extent the information requested is not currently available or is not applicable, the utility will clearly note and explain this in the appropriate location in the plan, narrative, or schedule.	As Applicable
Guideline (D)	Each utility shall provide a narrative summary detailing the major trends, events, and/or conditions reflected in the forecasted data submitted in response to these guidelines.	Chapter 1 Significant Development and Context for the Integrated Planning Process
Guideline (D)(1)	1. Discussion regarding the forecasted peak load obligation and energy requirements. PJM members should also discuss the relationship of the utility's expected non-coincident peak and its expected PJM related load obligations.	Section 4.1 Load Forecast
Guideline (D)(2)	2. Discussion regarding company goals and plans in response to directives of Chapters 23 and 24 of Title 56 of the Code of Virginia, including compliance with energy efficiency, energy conservation, demand-side and response programs, and the provision of electricity from renewable energy resources.	Executive Summary Section 2.2 Alternative Plans Section 5.4.1 Solar, Onshore Wind, and Energy Storage Appendix 3A Generation Under Construction Appendix 6A Description of Active DSM Programs Appendix 6F Description of Proposed DSM Programs
Guideline (D)(3)	3. Discussion regarding the complete planning process, including timelines, assumptions, reviews, approvals, etc., of the company's plans. For PJM members, the discussion should also describe how the IRP integrates into the complete planning process of PJM.	Chapter 4 Generation - Planning Assumptions
Guideline (D)(4)	4. Discussion of the critical input assumptions to determine the load forecast and expected changes in load growth including factors such as energy conservation, efficiency, load management, demand response, variations in customer class sizes, expected levels of economic activity, variations in fuel prices and appliance inventories, etc.	Section 4.1 Load Forecast Appendix 4M Economic Assumptions
Guideline (D)(5)	5. Discussion regarding cost/benefit analyses and the results of such factors on this plan, including the methodology used to consider equal or comparable treatment afforded both the demand-side options and supply-side resources.	Chapter 4 Generation - Planning Assumptions Chapter 5 Generation - Supply-Side Resources Chapter 6 Generation - Demand-Side Management
Guideline (D)(6)	6. Planned changes in operating characteristics such as unit retirements, unit uprates or derates, changes in unit availabilities, changes in capacity resource mix, changes in fuel supplies or transport, emissions compliance, unit performance, etc.	Section 4.9 Gas Transportation Cost Assumptions Section 5.2 Evaluation of Existing Generation Appendix 5J Potential Unit Retirements Appendix 5K Planned Changes to Existing Generation Units Appendix 5L Environmental Regulations
Guideline (D)(7)	7. Discussion regarding the effectiveness of the utility's IRP to meet its load obligations with supply-side and demand-side resources to enable the utility to provide reliable service at reasonable prices over the long term.	Section 2.2 Alternative Plans Section 2.4 NPV Results Section 2.5 Virginia Consolidated Bill Analysis

Citation	Requirement	2023 Plan Section
Guideline (E)	By September 1, 2009, and every two years thereafter, each utility shall file with the Commission its then current integrated resource plan, which shall include all information required by these guidelines for the ensuing 15-year planning period along with the prior three-year historical period. The process and analyses shall be described in a narrative discussion and the results presented in tabular format using an EXCEL spreadsheet format, similar to the attached sample schedules, and be provided in both printed and electronic media. For those utilities that operate as part of a multi-state integrated power system, the schedules should be submitted for both the individual company and the generation planning pool of which the utility is a member. The top line stating the company name should indicate that the data reflects the individual utility company or the total system. For partial ownership of any facility, please provide the percent ownership and footnote accordingly	2023 Plan
Guideline (E)	Each filing shall include a five-year action plan that discusses those specific actions currently being taken by the utility to implement the options or activities chosen as appropriate per the IRP.	Chapter 3 Short-Term Action Plan
Guideline (E)	If a utility considers certain information in its IRP to be proprietary or confidential, the utility may so designate, file separately and request such treatment in accordance with the Commission's Rules of Practice and Procedures.	Motion for Protective Order
Guideline (E)	As § 56-599 E requires the giving of notice and an opportunity to be heard, each utility shall also include a copy of its proposed notice to be used to afford such an opportunity.	2023 Plan Proposed Notice
Guideline (F)(1)	1. Forecast of Load. The forecast shall include descriptions of the methods, models, and assumptions used by the utility to prepare its forecasts of its loads, requirements associated with the utility's PJM load obligation (MW) if appropriate, the utility's peak load (MW) and energy sales (MWh) and the variables used in the models	Section 4.1 Load Forecast
Guideline (F)(1)(a)	a. The most recent three-year history and 15-year forecast of energy sales (kWh) by each customer class	Appendix 4A Total Sales by Customer Class (DOM LSE) (GWh) Appendix 4B Virginia Sales by Customer Class (DOM LSE) (GWh) Appendix 4C North Carolina Sales by Customer Class (DOM LSE) (GWh)
Guideline (F)(1)(b)	b. The most recent three-year history and 15-year forecast of the utility's peak load and the expected load obligation to satisfy PJM's coincident peak forecast if appropriate, and the utility's coincident peak load and associated noncoincident peak load for summer and winter seasons of each year (prior to any DSM), annual energy forecasts, and resultant reserve margins. During the forecast period, the tabulation shall also indicate the projected effects of incremental demand-side options on the forecasted annual energy and peak loads	Appendix 4H Projected Summer & Winter Peak Load & Energy Forecast for Plan B Appendix 4I Required Reserve Margin for Plan B
Guideline (F)(1)(c)	c. Where future resources are required, a description and associated characteristics of the option that the utility proposes to use to address the forecasted need	Section 5.5 Future Supply-Side Generation
Guideline (F)(2)	2. Supply-side Resources. The forecast shall provide data for its existing and planned electric generating facilities (including planned additions and retirements and rating changes, as well as firm purchase contracts, including cogeneration and small power production) and a narrative description of the driver(s) underlying such anticipated changes such as expected environmental compliance, carbon restrictions, technology enhancements, etc.	Chapter 1 Significant Developments and Context for Integrated Planning Process Chapter 5 Generation - Supply-Side Resources Appendix 5L Environmental Regulations
Guideline (F)(2)(a)	a. Existing Generation. For existing units in service: i. Type of fuel(s) used ii. Type of unit (e.g., base, intermediate, or peaking) iii. Location of each existing unit iv. Commercial Operation Date v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) vi. Units to be placed in reserve shutdown or retired from service with expected date of shutdown or retirement and an economic analysis supporting the planned retirement or shutdown dates vii. Units with specific plans for life extension, refurbishment, fuel conversion, modification or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, expected return to service date, capacity rating upon return to service, a general description of work to be performed as well as an economic analysis supporting such plans for existing units viii. Major capital improvements such as the addition of scrubbers, shall be evaluated through the IRP analysis to assess whether such improvements are cost justified when compared to other alternatives, including retirement and replacement of such resources ix. Other changes to existing generating units that are expected to increase or decrease generation capability of such units.	Section 5.2 Evaluation of Existing Generation Appendix 5A Existing Generation Units in Service Appendix 5J Potential Unit Retirements Appendix 5K Planned Changes to Existing Generation Units
Guideline (F)(2)(b)	b. Assessment of Supply-side Resources. Include the current overall assessment of existing and potential traditional and alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent IRP or annual report.	Section 5.5 Future Supply-Side Generation

Citation	Requirement	2023 Plan Section
Guideline (F)(2)(b)(i)	i. For the currently operational or potential future supply-side energy resources included, provide information on the capacity and energy available or projected to be available from the resource and associated costs. The utility shall also provide this information for any actual or potential supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.	Section 3.1 STAP - Generation Appendix 5O Renewable Resources for Plan B Appendix 5P Potential Supply-Side Resources for Plan B Appendix 5Q Summer Capacity Position for Plan B Appendix 5R Capacity Position for Plan B Appendix 5S Construction Forecast for Plan B
Guideline (F)(2)(b)(ii)	ii. For supply-side energy resources evaluated but rejected, a description of the resource; the potential capacity and energy associated with the resource; estimated costs and the reasons for the rejection of the resource.	Section 5.5.1 Supply-Side Resource Options
Guideline (F)(2)(c)	c. Planned Generation Additions. A list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition: i. Type of conventional or alternative facility and fuel(s) used ii. Type of unit (e.g. baseload, intermediate, peaking) iii. Location of each planned unit, including description of locational benefits identified by PJM and/or the utility iv. Expected Commercial Operation Date v. Size (nameplate, dependable operating capacity, and expected capacity value to meet load obligation (MW)) vi. Summaries of the analyses supporting such new generation additions, including its type of fuel and designation as base, intermediate, or peaking capacity vii. Estimated cost of planned unit additions to compare with demand-side options	Section 5.3 Generation Under Construction Section 5.4 Generation Resources Under Development Appendix 3A Generation under Construction Appendix 3B Planned Generation under Development Appendix 6P Comparison of Per MWh Costs of Selected Resources
Guideline (F)(2)(d)	d. Non-Utility Generation. A separate list of all non-utility electric generating facilities included in the IRP, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and contractual capacity (including any contract dispatch conditions or limitations), and the contractual start and expiration dates. The utility shall also indicate which facilities are included in their total supply of resources	Section 5.1.3 Power Purchase Agreements Appendix 5B Other Generation Units
Guideline (F)(3)	3. Capacity Position. Provide a narrative discussion and tabulation reflecting the capacity position of the utility in relation to satisfying PJM's load obligation, similar to Schedule 16 of the attached schedules.	Section 2.1 Capacity, Energy, and REC Position Appendix 2A Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E Appendix 5Q Summer Capacity Position for Plan B
Guideline (F)(4)	4. Wholesale Contracts for the Purchase and Sale of Power. A list of firm wholesale purchased power and sales contracts reflected in the plan, including the primary fuel type, designation as base, intermediate, or peaking capacity, contract capacity, location, commencement and expiration dates, and volume.	Appendix 4K Wholesale Power Sales Contracts
Guideline (F)(5)	5. Demand-side Options. Provide the results of its overall assessment of existing and potential demand-side option programs, including a descriptive summary of each analysis performed or used by the utility in its assessment and any changes to the methods and assumptions employed since its last IRP. Such descriptive summary, and corresponding schedules, shall clearly identify the total impact of each DSM program.	Chapter 6 Generation - Demand-Side Management Appendix 4L Load Duration Curves Appendix 6A Description of Active DSM Programs Appendix 6F Description of Proposed Programs Appendix 6O Projected Savings Attributable to DSM Programs in 2028 Appendix 6P Comparison of Per MWh Costs of Selected Resources
Guideline (F)(6)	6. Evaluation of Resource Options. Provide a description and a summary of the results of the utility's analyses of potential resource options and combinations of resource options performed by it pursuant to these guidelines to determine its integrated resource plan. IRP filings should identify and include forecasted transmission interconnection and enhancement costs associated with specific resources evaluated in conjunction with the analysis of resource options.	Section 4.7.5 Renewable Energy Interconnection and Integration Costs Section 5.5 Future Supply-Side Resource Options
Guideline (F)(7)	7. Comparative Costs of Options. Provide detailed information on levelized busbar costs, annual revenue requirements or equivalent methodology for various supply-side options and demand-side options to permit comparison of such resources on equitable footing. Such data should be tabulated and at a minimum, reflect the resource's heat rate, variable and fixed operating maintenance costs, expected service life, overnight construction costs, fixed charged rate, and the basis of escalation for each component.	Section 5.5.2 Levelized Busbar Costs / Levelized Cost of Energy Appendix 5M Tabular Results of Busbar Appendix 5N Busbar Assumptions Appendix 6P Comparison of Per MWh Costs of Selected Resources

Citation	Requirement	2023 Plan Section
Schedule 1	Peak load and energy forecast	**Appendix 4H** Projected Summer & Winter Peak Load & Energy Forecast for Plan B
Schedule 2	Generation output	**Appendix 5G** Energy Generation by Type for Plan B (GWh)
Schedule 3	System output mix	**Appendix 5H** Energy Generation by Type for Plan B (%)
Schedule 4	Seasonal capability	**Appendix 5R** Capacity Position for Plan B
Schedule 5	Seasonal load	**Appendix 4J** Summer and Winter Peak for Plan B
Schedule 6	Reserve margin	**Appendix 4I** Required Reserve Margin for Plan B
Schedule 7	Installed capacity	**Appendix 5F** Existing Capacity for Plan B
Schedule 8	Equivalent availability factor	**Appendix 5C** Equivalent Availability Factor for Plan B
Schedule 9	Net capactiy factor	**Appendix 5D** Net Capacity Factor
Schedule 10	Average heat rate	**Appendix 5E** Heat Rates for Plan B
Schedule 11	Renewable resources	**Appendix 5O** Renewable Resources for Plan B
Schedule 12	DSM programs	**Appendix 6D** Approved Programs Energy Savings for Plan B (MWh) (System Level) **Appendix 6I** Proposed Programs Energy Savings for Plan B (MWh) (System Level) **Appendix 6L** Future Undesignated EE Energy Savings for Plan B (MWh) (System Level)
Schedule 13	Unit size uprate and derate	**Appendix 5K** Planned Changes to Existing Generation Units
Schedule 14	Existing unit performance data	**Appendix 5A** Existing Generation Units in Service **Appendix 5B** Other Generation Units
Schedule 15	Planned unit performance data	**Appendix 3A** Generation under Construction **Appendix 3B** Planned Generation under Development **Appendix 5P** Potential Supply-Side Resources for Plan B
Schedule 16	Utility capacity position	**Appendix 5Q** Summer Capacity Position for Plan B
Schedule 17	Construction forecast	**Appendix 5S** Construction Forecast for Plan B
Schedule 18	Fuel data	**Appendix 4O** Delivered Fuel Data
Case No. PUR-2022-00124 Final Order at 8	The Commission finds reasonable Dominion's proposal to address—in its next IRP proceeding—(i) the load forecast, modeling, and planning implications of projecting (and conversely not projecting) a portion of data center load increases coming from ARBs, and (ii) its modeling assumption for energy efficiency beginning in 2026.	**Section 4.1.3** Energy Efficiency Adjustment **Section 9.3** Accelerated Renewable Energy Buyers
Case No. PUR-2022-00147 Final Order at 2	Model any impacts of the Inflation Reducation Act	**Section 4.6** Federal Tax Credit Assumptions
Case No. PUR-2020-00035 Final Order at 7, n.25	In future IRPs and updates, the Company shall, at a minimum, include the following sensitivities: (i) high and low PJM energy prices; (ii) high and low PJM capacity prices; (iii) high and low REC prices; (iv) high and low construction costs; (v) high and low fuel prices; (vi) high and low load forecast scenarios; and (vii) the impact of not meeting legislatively mandated energy efficiency savings targets.	**Section 2.6** Sensitivity Analyses
Case No. PUR-2020-00035 Final Order at 9	The Commission directs the Company to include in future IRPs and updates the up-to-date reliability analyses of the impacts of retiring traditional fossil generation and adding growing amounts of renewable energy resources on the Company's electric system.	**Section 2.3** Reliability Analyses of Alternative Plans **Section 7.5** Transmission System Reliability Analyses
Case No. PUR-2020-00035 Final Order at 9	In the future, the Company should also include one or more plans without [a 970 MW CT] "placeholder" additions to address reliability concerns for comparison purposes and to improve transparency in the Company's planning processes	**Section 2.2** Alternative Plans
Case No. PUR-2020-00035 Final Order at 10	We agree that it is appropriate to model retirements as part of the PLEXOS modeling; however, we will also require the Company, for the time being, to continue to file a separate retirement analysis comparable to the economic analysis performed in this case	**Section 5.2.1** Retirements

Citation	Requirement	2023 Plan Section
Case No. PUR-2020-00035 Final Order at 11, n.50	Staff recommended and the Company did not object to providing certain capacity-related information in future IRPs and updates, and we so direct as agreed by Staff and the Company. Includes: (i) the most recent PJM Dominion Zone coincident peak forecast; (ii) the most recent PJM Dominion Zone non-coincident peak forecast; (iii) versions of both aforementioned forecasts scaled down to the Dominion load serving entity level; (iv) each Company-owned generation unit interconnected at the transmission-level in the PJM Dominion Zone and the associated nameplate capacity; (v) all Company-owned units that have cleared the PJM capacity market or have capacity performance obligations; (vi) any notification to PJM of the Company's intention to retire or deactivate Company-owned units.	**Appendix 2B** Capacity Information Directed by the SCC
Case No. PUR-2020-00035 Final Order at 11-12 and n.53	In future IRPs and updates, the Company should study and report separately on its summer and winter capacity and energy needs, and its alternative plans' ability to meet those requirements. The Company should also give due consideration to market purchases during the winter from the PJM wholesale market, which remains a summer peaking entity; this consideration should include market purchases from merchant generators located within the Dominion Zone that are not subject to a transmission import capacity constraint.	**Section 2.1** Capacity, Energy, and REC Positions **Section 2.2** Alternative Plans **Appendix 2A** Capacity, Energy, and RECs for Alternative Plans A, B, C, D, and E **Appendix 5T** Winter Capacity for Alternative Plans A, B, C, D, and E
Case No. PUR-2020-00035 Final Order at 12	We direct the Company to continue to model energy efficiency targets after 2025	**Section 4.1.3** Energy Efficiency Adjustment
Case No. PUR-2020-00035 Final Order at 14 and n.56	Dominion proposes that future IRPs and updates include a least cost VCEA plan that would meet (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA. For this plan, the Company proposes not to force the model to select any specific resource nor exclude any reasonable resource and allow the model to optimize the accompanying resource plan. Based on the record in this proceeding, we find this proposal to be reasonable at this time. While the Commission recognizes that certain build constraints may be necessary under certain circumstances, the reasonableness of any such build constraints will be subject to Commission review in future proceedings.	**Section 2.2** Alternative Plans **Section 4.11** Least-Cost Plan Assumptions
Case No. PUR-2020-00035 Final Order at 14-15	The Commission finds that the Company should address environmental justice in future IRPs and updates, as appropriate. As one example, the Company may consider the impact of unit retirement decisions on environmental justice communities or fenceline communities.	**Section 9.1** Environmental Justice
Case No. PUR-2020-00035 Final Order at 15-16	The Commission will require Dominion to file an updated bill analysis by plan in future IRPs and updates with the following modifications: • The Company shall provide bill impacts over the next ten years for the least cost VCEA plan, the Company's preferred plan, and any additional plans presented, including residential, small general service and large general service customer bills. Each update shall include an additional year of projections beyond 2030 as each year passes and should consistently be compared back to the actual bill as of May 1, 2020. • As proposed by Staff, the Company shall use class allocation factors and projected sales recently used to set rate adjustment clause rates in the bill analysis. • In addition to projections, the analysis shall include actual bill impact information as each year passes. For example, in the 2021 update filing, the Company would include the actual bill information as of December 31, 2020 in the bill analysis.	**Section 2.5** Virginia Consolidated Bill Analysis **Va. Addendum 1** Virginia Consolidated Bill Analysis
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 2. Continue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Senate Bill 966 (Enactment Clause 15), both as an energy reduction and a supply resource, and separately identify the load associated with data centers.	**Section 4.1** Load Forecast
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 3. Model battery storage using the most updated cost estimates available.	**Section 4.8** Storage-Related Assumptions
Case No. PUR-2018-00065 Final Order at 11	In future IRPs, the Company shall: 4. Model compliance with the Regional Greenhouse Gas Initiative.	**Section 2.6** Sensitivity Analyses **Section 4.4** Commodity Price Assumptions
Case No. PUR-2018-00065 Final Order at 11 Case No. PUR-2018-00065 Dec. 2018 Order at 5, n. 14	In future IRPs, the Company shall: 5. Model gas transportation costs, including a reasonable estimate of fuel transportation costs (firm and interruptible transportation, if applicable) associated with all natural gas generation facilities as well as fuel commodity costs, consistent with the December 2018 Order	**Section 4.9** Gas Transportation Cost Assumptions
Case No. PUR-2018-00065 Final Order at 11-12 Case No. PUR-2018-00065 Order on Reconsideration at 5	In future IRPs, the Company shall: 7. Model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Dominion's Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (The Commission additionally noted that for the 2020 IRP, the Company should use the three-year average of calendar years 2017-2019. For those solar tracking facilities that have not been in service for three years, the Company should use the historic data that is available.) (b) 25%. In the Order on Reconsideration, the Commission approved the Compay's request to run one of the capacity factors contained in Directive #7 as a sensitivity; however, if the Company chooses to do so, it shall model the actual capacity performance of Dominion's Company-owned solar tracking fleet as the baseline assumption and use 25% as the sensitivity.	**Section 4.7.1** New Solar Resources
Case No. PUR-2018-00065 Final Order at 12	In future IRPs, the Company shall: 8. Systematically evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects (Code § 56-599 B 10). For identified grid transformation projects, the Company shall include: (a) A detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) Detailed cost estimates of each proposed investment; (c) The benefits associated with each proposed investment; and (d) Alternatives considered for each proposed investment.	**Chapter 8** Distribution **Va. Addendum 2** GT Plan Document

Citation	Requirement	2023 Plan Section
Case No. PUR-2018-00065 Final Order at 12, n. 49	In future IRPs, the Company shall: 9. Provide a schedule identifying the Company's contribution towards meeting the 5,000 MW target identified in Code § 56-585.1:4, including (a) a list of each project in service or under construction; (b) the nameplate capacity of each project; (c) the actual or projected in-service date; (d) whether the project is Company-build or a third-party PPA; and (e) the cost recovery mechanism (e.g., fuel, base rates, RAC, ring-fence arrangement, etc.) The Company shall also maintain this information on an on-going basis and provide it to Staff upon request.	Appendix 5I Solar and Wind Generating Facilities
Case No. PUR-2018-00065 Final Order at 12	In future IRPs, the Company shall: 10. Provide, in addition to a list of planned transmission projects, the projected cost per transmission project and indicate whether or not each project is subject to PJM's Regional Transmission Expansion Planning process.	Appendix 3C List of Planned Transmission Projects during the Planning Period
Case No. PUE-2016-00049 Final Order at 3 Case No. PUE-2015-00035 Final Order at 18	Dominion shall continue to comply with all requirements directed in prior IRP orders, including the requirement to include an index that identifies the specific location(s) within the IRP that complies with each such requirement.	2023 Plan Reference Index
Case No. PUE-2015-00035 Final Order at 10	The Commission directs the Company to: continue to investigate the feasibility and cost of extending the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2	Section 5.2.4 Nuclear License Extensions
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: include a more detailed analysis of market alternatives, especially third-party purchases that may provide long-term price stability, and includes, but is not limited to, wind and solar resources	Section 4.7 Renewable Energy-Related Assumptions Section 5.5.3 Third-Party Market Alternatives
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: examine wind and solar purchases at prices (including prices available through long-term purchase power agreements) and in quantities that are being seen in the market at the time the Company prepares its IRP filings	Section 4.7 Renewable Energy-Related Assumptions Section 5.5.3 Third-Party Market Alternatives
Case No. PUE-2015-00035 Final Order at 16 Case No. PUE-2013-00088 Final Order at 7	In future IRP filings, Dominion shall: provide a comparison of the cost of purchasing power from wind and solar resources from third-party vendors versus self-build options, including off-shore and on-shore wind, with this comparison including information from a variety of third-party vendors	Section 4.7 Renewable Energy-Related Assumptions Section 5.5.3 Third-Party Market Alternatives
Case No. PUE-2015-00035 Final Order at 17	In future IRPs, Dominion shall: develop a plan for identifying, quantifying, and mitigating cost and integration issues associated with greater reliance on solar photovoltaic generation	Section 4.7.5 Renewable Energy Interconnection and Integration Costs
Case No. PUE-2013-00088 Final Order at 4	Next, we find that in future IRP filings, the Company shall provide further analysis related to the construction of North Anna 3 and the future of Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, all of which have licenses that are scheduled to expire within the next thirty years.	Section 5.2.4 Nuclear License Extensions Section 5.4 Generation Resources Under Development
Case No. PUE-2013-00088 Final Order at 5-6	The Company shall also provide status updates on any discussions it engages in with the United States Nuclear Regulatory Commission on a possible extension for the operating licenses for Surry Unit 1, Surry Unit 2, North Anna Unit 1, and North Anna Unit 2, in its future IRP and IRP update filings.	Section 5.2.4 Nuclear License Extensions
Case No. PUE-2013-00088 Final Order at 8	Next, the Commission finds that in future IRP filings, Dominion Virginia Power should compare the cost of its demand-side management proposals to the cost of new generating resource alternatives. Specifically, Staff has suggested that it would be informative to compare the Company's expected demand-side management costs per megawatt hour saved to its expected supply side costs per megawatt hour. We agree and direct the Company to evaluate demand-side management alternatives using this methodology.	Appendix 6P Comparison of Per MWh Costs of Selected Resources
Case No. PUE-2013-00088 Final Order at 8	Further, we direct Dominion Virginia Power to include a broad band of prices used in future forecasting assumptions, such as forecasting assumptions related to fuel prices, effluent prices, market prices and renewable energy credit costs, in order to continue to set reasonable boundaries around the modeling assumptions, and to continue to refine the specific assumptions and sensitivity adjustments of its modeling data in future IRP filings.	Section 2.6 Sensitivity Analyses Section 4.4 Commodity Price Assumptions Appendix 4N ICF Commodity Price Forecasts

NOTICE TO THE PUBLIC
OF A FILING BY VIRGINIA ELECTRIC AND POWER COMPANY
OF ITS INTEGRATED RESOURCE PLAN
CASE NO. PUR-2023-00066

On May 1, 2023, Virginia Electric and Power Company (the "Company"), submitted to the State Corporation Commission ("Commission") its 2023 Integrated Resource Plan (the "2023 Plan" or "Plan") pursuant to § 56-597 *et seq*. of the Code of Virginia ("Va. Code"). An integrated resource plan, as defined by Va. Code § 56-597, is "a document developed by an electric utility that provides a forecast of its load obligations and a plan to meet those obligations by supply side and demand side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility." Pursuant to Va. Code § 56-599 D, the Commission will analyze the Company's Plan and make a determination as to whether the Plan is reasonable and in the public interest.

On **[date]**, the Commission entered an Order for Notice and Comment ("Procedural Order") that, among other things, directed the Company to provide notice to the public and offered interested persons an opportunity to comment or request a hearing on the Company's 2023 Plan.

An electronic copy of the Company's Plan may be obtained, at no charge, by requesting it in writing from Nicole M. Allaband, Esquire, McGuireWoods LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219, or nallaband@mcguirewoods.com. If acceptable to the requesting party, the Company may provide the documents by electronic means. Interested persons may also download unofficial copies of the 2023 Plan and other documents from the Commission's website: http://www.scc.virginia.gov/case.

On or before **[date]**, interested persons may file written comments concerning the issues in this case with Bernard Logan, Clerk, State Corporation Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218-2118. Interested persons desiring to submit comments electronically may do so by following the instructions found on the Commission's website: http://www.scc.virginia.gov/case. Comments shall refer to Case No. PUR-2023-00066.

On or before **[date]**, interested persons may request that the Commission convene a hearing on the Company's 2023 Plan by filing a request for a hearing with the Clerk of the Commission at the address set forth above. Requests for hearing must include: (i) a precise statement of the filing party's interest in the proceeding; (ii) a statement of the specific action sought to the extent then known; (iii) a statement of the legal basis for such action; and (iv) a precise statement why a hearing should be conducted in this matter.

Any interested person may participate as a respondent in this proceeding by filing a notice of participation on or before **[date]**. Such notice of participation shall include the email addresses of such parties and their counsel. The respondent simultaneously shall serve a copy of the notice of participation on counsel to the Company. Pursuant to 5 VAC 5-20-80, *Participation as a respondent*, of the Commission's Rules of Practice and Procedure ("Rules of Practice"), any notice of participation shall set forth: (i) a precise statement of the interest of the respondent; (ii) a statement of the specific action sought to the extent known; and (iii) the factual and legal basis for the action. Any organization, corporation, or government body participating as a respondent must be represented by counsel as required by Rule 5 VAC 5-20-30, *Counsel*, of the Rules of Practice. All filings shall refer to Case No. PUR-2023-00066. For additional information about participation as a respondent, any person or entity should obtain a copy of the Commission's Procedural Order.

The Commission's Rules of Practice may be viewed at http://www.virginia.gov/case. A printed copy of the Commission's Rules of Practice and an official copy of the Commission's Procedural Order in this proceeding may be obtained from the Clerk of the Commission at the address set forth above.

VIRGINIA ELECTRIC AND POWER COMPANY

Dominion Energy®

Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan

Before the Virginia State Corporation Commission and North Carolina Utilities Commission

Case No. PUR-2023-00066
Docket No. E-100, Sub 192

Filed: May 1, 2023

Table of Contents

List of Acronyms

Acronym	Meaning
2020 Plan	2020 Integrated Resource Plan
2023 Plan	2023 Integrated Resource Plan
AC	Alternating Current
ACE Rule	Affordable Clean Energy Rule
AMI	Advanced Metering Infrastructure
ARB	Accelerated Renewable Energy Buyers
BATW	Bottom Ash Transport Water
BDM	Bass Diffusion Model
BESS	Battery Energy Storage System
BRA	Base Residual Auction
BSER	Best System of Emissions Reduction
¢/kWh	Cents per kilowatt-hour
CAGR	Compound Annual Growth Rate
CC	Combined-Cycle
CCR	Coal Combustion Residual
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
CIP	Customer Information Platform
CIR	Capacity Injection Rights
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
COD	Commercial Operation Date
COL	Combined Operating License
Company	Virginia Electric and Power Company
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
CVOW	Coastal Virginia Offshore Wind
CWA	Clean Water Act
DAC	Direct Air Capture
DC	Direct Current
DER	Distributed Energy Resource
DNV GL	DNV GL Energy Insights U.S.A.
Dominion Energy	Dominion Energy, Inc.
DOM LSE	Dominion Energy Load Serving Entity
DOM Zone	Dominion Energy Zone
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	U.S. Energy Information Administration

Acronym	Meaning
EFORd	Equivalent Forced Outage Rate Demand
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitations Guidelines
EM&V	Evaluation, Measurement and Verification
EO9	Virginia Executive Order 49
EPA	U.S. Environmental Protection Agency
ESCR	Effective Short Circuit Ratio
EV	Electric Vehicle
FACTS	Flexible Alternative Current Transmission Systems
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization
FIP	Federal Implementation Plan
FRR	Fixed Resource Requirement
GHG	Greenhouse Gas
GTSA	Grid Transformation and Security Act of 2018
GW	Gigawatts
GWh	Gigawatt Hours
HVDC	High-voltage Direct Current
ICF	ICF Resources, LLC
IDP	Integrated Distribution Planning
IIJA	Infrastructure Investment and Jobs Act of 2021
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
ISA	Interconnection Service Agreement
ITC	Investment Tax Credit
kV	Kilovolts
kW	Kilowatts
kWh	Kilowatt Hours
LCOE	Levelized Cost of Energy
LNG	Liquified Natural Gas
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MGD	Million Gallons per Day
Moody's	Moody's Analytics
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NCGS	North Carolina General Statute
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corporation
NOVEC	Northern Virginia Electric Cooperative
NO_x	Nitrogen Oxide

Acronym	Meaning
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	The National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NWA	Non-wires Alternatives
O&M	Operations and Maintenance
ODEC	Old Dominion Electric Cooperative
PJM	PJM Interconnection, L.L.C.
Plan	Integrated Resource Plan
Planning Period	15-year Period of 2024 to 2038
PLEXOS	PLEXOS Model
PPA	Power Purchase Agreement
Ppb	Parts Per Billion
PTC	Production Tax Credit
REC	Renewable Energy Certificate(s)
REPS	N.C. Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable Natural Gas
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCC	Virginia State Corporation Commission
SG	Standby Generation
SMR	Small Modular Reactor
SO_2	Sulfur Dioxide
Study Period	25-year Period of 2024 to 2048
SUP	Strategic Underground Program
ug/m^3	Microgram per cubic meter
V2G	Vehicle-to-grid
Va. Code	Code of Virginia
VCEA	Virginia Clean Economy Act
VCHEC	Virginia City Hybrid Energy Center
VEJA	Virginia Environmental Justice Act
WHP	Waste Heat to Power
WSP	Weatherization Service Providers

Introduction

Headquartered in Richmond, Virginia, Virginia Electric and Power Company (the "Company") currently serves approximately 2.7 million electric customers located in approximately 30,000 square miles of Virginia and North Carolina. The Company is a subsidiary of Dominion Energy, Inc. ("Dominion Energy")—one of the nation's largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 16 states with electricity or natural gas.

The Company's supply-side portfolio consists of 21,713 megawatts ("MW") of generation capacity, including approximately 1,164 MW of resources owned by third parties from which the Company purchases the output through power purchase agreements ("PPAs"). The Company's demand-side management ("DSM") portfolio consists of energy efficiency and demand response programs in Virginia and North Carolina. The Company owns approximately 6,800 miles of transmission lines at voltages ranging from 69 kilovolts ("kV") to 500 kV in Virginia, North Carolina, and West Virginia; and approximately 60,000 miles of distribution lines at voltages ranging from 4 kV to 46 kV in Virginia and North Carolina. The Company is a member of PJM Interconnection, LLC ("PJM"), the regional transmission organization ("RTO") coordinating the wholesale electric grid in the Mid-Atlantic region of the United States. The Company's service territory is located within the Dominion Energy Zone ("DOM Zone") in PJM. The 2023 Integrated Resource Plan (the "2023 Plan" or the "Plan") was prepared for the Dominion Energy Load Serving Entity ("DOM LSE") within PJM.

The Company files this 2023 Plan with the Virginia State Corporation Commission ("SCC") in accordance with § 56-597 *et seq.* of the Code of Virginia (or "Va. Code") and the SCC's guidelines issued on December 23, 2008, in Case No. PUE-2008-00099. The Company also files this 2023 Plan with the North Carolina Utilities Commission ("NCUC") in accordance with § 62-2 of the North Carolina General Statutes ("NCGS") and Rule R8-60 of NCUC's Rules and Regulations. The 2023 Plan also addresses requirements identified by the SCC and the NCUC in prior relevant orders, as well as current and pending provisions of state and federal law.

The 2023 Plan covers the 15-year period beginning in 2024 and continuing through 2038 (the "Planning Period"), using 2023 as the base year. In certain instances described herein, the Company evaluates the longer 25-year period of 2024 to 2048 (the "Study Period"). Overall, the 2023 Plan is meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and projections, and should be viewed in that context.

Executive Summary

The priorities of the Company have not changed—to provide reliable, affordable, and increasingly clean power to its customers. However, this year the long-term projected amount of power needed in the DOM Zone materially increased. The 2023 PJM Load Forecast included a significant increase in the expected peak and energy demand in the DOM Zone over the Planning Period, with annual peak and energy load growth of nearly 5% and 7% respectively, over the next decade. This increase is driven primarily by data centers and, to a lesser extent, electrification in both the Company's service territory and in other service areas within DOM Zone. Winter Storm Elliott on December 23 and 24, 2022, also magnified the need for dispatchable generation, backup fuel sources, and resources that are available to generate during winter peaks. Through the development of this 2023 Plan, the Company addresses these needs with a diverse portfolio of resources.

The Company is transforming its distribution grid to provide an enhanced platform for distributed energy resources ("DERs") and targeted DSM programs; more secure and reliable service, leading to the increased availability of DERs; and more ways for customers to save energy and money through DSM programs and other rate offerings. The Company has also received approval of new customer offerings in Virginia to support and incentivize the installation of charging infrastructure for electric vehicles ("EVs"), including an offering to support fleet electrification.

Over the long term, achieving the clean energy goals of Virginia, North Carolina, and the Company will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. This includes support for the testing and deployment of technologies, such as long duration energy storage; renewable natural gas; vehicle-to-grid; hydrogen; advanced nuclear; and carbon capture and sequestration, all of which have the potential to significantly reduce greenhouse gas emissions.

In this 2023 Plan, the Company presents five alternative plans (the "Alternative Plans") to meet customers' needs in the future under different scenarios, which are designed using constraint-based least-cost planning techniques and proven technologies:

- Plan A: This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory renewable energy portfolio standard program ("RPS Program") requirements of the Virginia Clean Economy Act ("VCEA"). The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- Plan B: This Alternative Plan includes the significant development of solar, wind, and energy storage envisioned by the VCEA, petitioned by 2035 and built by 2038. Plan B includes the development of six new small modular reactors ("SMRs") starting in 2034 and a second offshore wind project, providing carbon free power. This plan does require an increase in the Company's ability to import capacity and energy by 2040. Plan B also preserves existing generation and includes several new gas combustion turbines to address future energy and system reliability needs.

- Plan C: This Alternative Plan is like Plan B in preserving existing generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- Plan D: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero carbon dioxide ("CO_2") emissions from the Company's fleet in 2046. In order to retire all carbon-emitting units by the end of 2045, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building over 4,500 MW of incremental energy storage and more than 3,000 MW of incremental SMRs to meet this need when compared to Plan B. Even with these additional resources, Plan D results in the Company purchasing 10,800 MW of capacity in 2045 and beyond, raising significant concerns about system reliability and energy independence, including over-reliance on out-of-state capacity to meet customer needs. This Plan will also require a substantial increase in energy purchase limits. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan D approach to maintain system reliability.

- Plan E: This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Like Plan D, Plan E would require the Company to build and buy significant incremental capacity and energy to reliably meet customer load. Over time as more renewable energy and energy storage resources are added to the system, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan E approach to maintain system reliability.

All Alternative Plans utilize the load forecast prepared by PJM; assume a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia; and assume that Virginia exits the Regional Greenhouse Gas Initiative ("RGGI") before January 1, 2024. All plans assume the retirement of Yorktown 3, Chesterfield 5, and Chesterfield 6 in May 2023. The 2023 Plan also presents multiple sensitivities on various assumptions. Notably, the Company presents a high load sensitivity that would require increased capacity and energy purchases even earlier in the Plan. Increased market reliance shown in sensitivities with higher load or less energy efficiency is a reliability concern. The Company also presents sensitivities on all Alternative Plans that show the higher cost to customers if Virginia remains in RGGI.

The following table presents a high-level summary of the Alternative Plans. The resource additions shown here are incremental to existing generation and approved generation under construction, including nearly 2,600 MW of offshore wind.

Executive Summary Table: 2023 Plan Results

	Plan A	Plan B	Plan C	Plan D	Plan E
NPV Total ($B)	$109.70	$127.70	$127.20	$140.90	$138.00
Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	43.8 M	35.9 M	36 M	0 M	0 M
Solar (MW)	10,800 15-yr 19,800 25-yr	10,875 15-yr 19,875 25-yr	10,800 15-yr 19,800 25-yr	10,875 15-yr 23,955 25-yr	11,094 15-yr 24,294 25-yr
Wind (MW)	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr
Storage (MW)	1,050 15-yr 3,960 25-yr	2,370 15-yr 5,190 25-yr	2,220 15-yr 5,220 25-yr	2,370 15-yr 9,780 25-yr	2,910 15-yr 10,350 25-yr
Nuclear (MW)	-- 15-yr -- 25-yr	804 15-yr 1,608 25-yr	804 15-yr 1,608 25-yr	1,608 15-yr 4,824 25-yr	1,072 15-yr 4,288 25-yr
Natural Gas Fired (MW)	5,905 15-yr 9,300 25-yr	2,910 15-yr 2,910 25-yr	2,910 15-yr 2,910 25-yr	970 15-yr 970 25-yr	970 15-yr 970 25-yr
Retirements (MW)	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr 11,399 25-yr	-- 15-yr 11,399 25-yr

As can be seen in the Summary Table, all Alternative Plans show significant solar, wind and energy storage development over the 25-year Study Period. Additionally, Plans B through E include development of SMRs. Due to an increasing load forecast, and the need for dispatchable generation, the Alternative Plans show additional natural gas-fired resources and preserve existing carbon-emitting units beyond statutory retirement deadlines established in the VCEA. The law explicitly authorizes the Company to petition the SCC for relief from these requirements on the basis that the unit retirements would threaten the reliability or security of electric service to customers. If the Company ultimately retires all carbon-emitting generation by the end of 2045, as shown in Plans D and E, significant incremental wind, solar, nuclear, and energy storage resources are needed. While all Alternative Plans incorporate only known technologies, the Company fully expects that new technologies could take the place of today's technologies over the 15-year Planning Period and the 25-year Study Period.

Going forward, long-term integrated resource plans will evolve and will continue to support the cleaner future envisioned by public policy, by lawmakers, and by the Company. As noted, this future, while achievable, will require supportive legislative and regulatory policies, technological advancements, grid modernization, and broader investments across the economy. It will also require further study and analyses of necessary investments in the transmission and distribution systems to ensure the reliable electric service that customers expect and deserve. For example, the Company knows that greater investments in some plans are required to support greater capacity and energy imports. Overall, the Company's deliberate transitional approach to a cleaner future has, and will continue, to provide customers a path to clean energy that meets public policy objectives while maintaining the standard of reliability necessary to power Virginia's and North Carolina's modern economies.

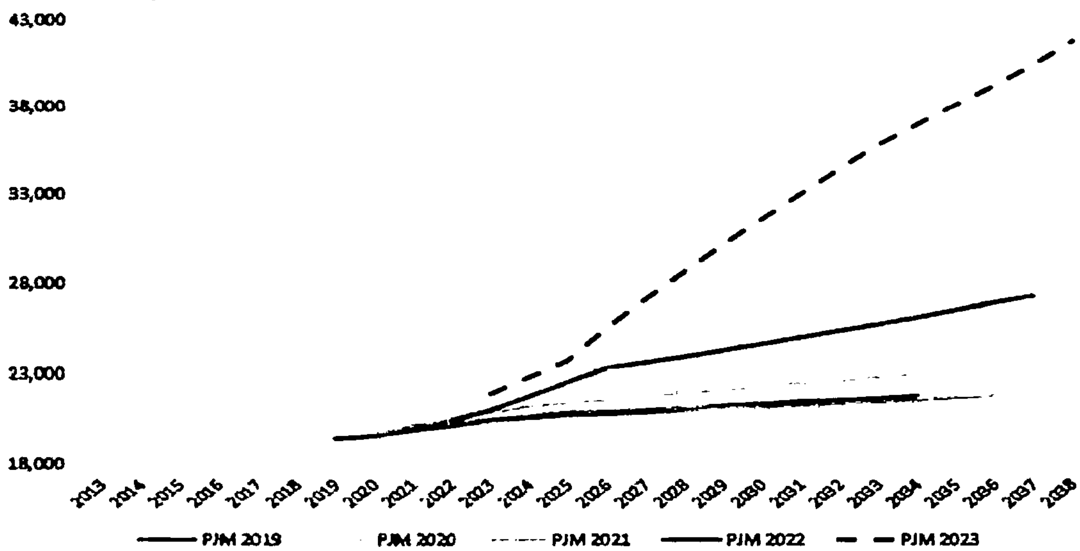
Chapter 1: Significant Developments and Context for the Integrated Planning Process

The Company's comprehensive planning process considers emerging policy, market, regulatory, and technical developments that could affect its operations and, in turn, its customers. The Company provides the following discussion of significant developments requiring a major revision to previous modeling, consistent with the requirements of the SCC and the NCUC.

1.1 PJM Load Forecast and Energy Transition Risks

PJM's 2023 load forecast for the DOM Zone increased significantly relative to the prior year's forecast, as can be seen in Figure 1.1.1. In this forecast, PJM made several changes to its load forecasting methodology, most of which followed an independent consultant's review of PJM's modeling process. These changes included replacing annual/quarterly end-use indices with monthly/daily indices, replacing daily models with hourly models, and incorporating a data center forecast covering fifteen years, instead of just five years, from load serving entities like the Company with significant data center growth. Rising energy and peak growth from data centers in Virginia is a key driver of PJM's DOM Zone forecast in overall energy and peak demand.

Figure 1.1.1: PJM Summer Peak Forecast for DOM Zone (MW)



Even with the above changes, a few challenges remain with using PJM's load forecast for the Company's long-term resource planning process related to region-specific considerations (*e.g.*, class-level sales modeling, electrification, energy efficiency, net metering, etc.), forecast timing, and forecast translation from the DOM Zone to the DOM LSE. These challenges are not a criticism of the PJM forecast but are associated with the SCC-required use of that forecast for the Company's long-term planning. Accordingly, while the Company has utilized the 2023 PJM Load Forecast in the development of all Alternative Plans, as required, the Company also shows a sensitivity of Alternative Plan B using the 2023 Company Load Forecast.

In February 2023, PJM issued an "Energy Transition in PJM: Resource Retirements, Replacements, & Risks" report highlighting the trends that are increasing reliability risks. Specifically, PJM identified:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region due to the timing of resource availability, load growth, and new generation.
- Thermal generators are retiring at a rapid pace throughout the PJM region due to government and private sector policies, as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, multiple megawatts of these resources are needed to replace one megawatt of thermal generation.

PJM forecasts DOM Zone load by isolating data center load, and requests the Company, as well as other load serving entities, provide a data center load forecast. The Company prepares this load forecast using statistical regression and confidential and proprietary customer information. A detailed description of the Company's forecasting method can be found in Section 4.1.5, ***Data Center Forecast***. In prior years, PJM has requested a five-year data center projection and used a long-term historical average growth rate to project data center growth beyond five years, but in preparation of its 2023 load forecast, PJM requested a fifteen-year data center forecast. The resulting growth seen in the PJM DOM Zone forecast this year is largely driven by this change.

1.2 Significant Federal Legislation

1.2.1 Inflation Reduction Act

In August 2022, the Inflation Reduction Act of 2022 ("IRA") became law. The IRA includes various climate and energy provisions expected to have a positive effect on current and future Company clean energy investments. The IRA generally extends and adds incentives to promote clean energy nationwide, including approximately $369 billion for climate and clean energy provisions, such as increased federal tax credits for solar, wind, storage, and nuclear.

There are generally two types of federal tax credits available to incentivize investment in renewable energy generation facilities—investment tax credits ("ITCs") or production tax credits ("PTCs"). ITCs are based on the amount of eligible capital invested in a facility. The ITC is a one-time credit that is calculated by multiplying the credit percentage times the amount of qualified capital (*i.e.*, the cost of constructing or acquiring property that is eligible for the credit, such as solar or wind energy property). PTCs are based on the amount of renewable electricity produced and sold by a facility. The PTC is calculated annually for a ten-year period by multiplying the credit amount, adjusted annually for inflation, by the kilowatt-hours ("kWh") of electricity produced and sold by the facility during the year.

The IRA includes several provisions relevant to the Company. The IRA extends ITCs and PTCs for renewable energy technologies, including wind and solar, for at least ten years and expands the qualifying technologies to include hydrogen, biogas, and, after 2024, other zero-emissions facilities, including new nuclear. The IRA also expands the qualifying technologies for ITCs specifically to include stand-alone storage greater than five kilowatts ("kW"). Any incremental credit that the Company receives as a result of the IRA will be passed on to customers through lower project costs. Eligible property for credits is expanded to include interconnection property for certain small projects (*i.e.*, five MWs or less). Section 4.6, ***Federal Tax Credit Assumptions***, provides details on how the Company incorporated the Inflation Reduction Act into its modeling for the 2023 Plan.

1.2.2 Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act of 2021 ("IIJA") was enacted in November 2021 to comprehensively invest in the nation's infrastructure. Relevant to utilities, the IIJA aims to build a national network of EV chargers; upgrade power infrastructure to deliver clean, reliable energy across the country and deploy cutting-edge energy technology to achieve a zero-emissions future; and make infrastructure resilient against the impacts of climate change, cyber-attacks, and extreme weather events. The IIJA provides several competitive funding opportunities, some of which will be directly available to utilities, and some of which will be partnership-based, meaning, for example, partnerships between the Company and school districts in its territory for electrification of school buses.

Generally, the Company intends to actively participate in IIJA opportunities that align with its operations in Virginia and North Carolina while providing overall net benefits to its customers. The Company has submitted applications and concept papers for IIJA direct funding opportunities, including expansion of rural broadband, grid modernization, and energy storage. The Company has also taken steps to support its partners indirectly through transportation electrification initiatives with the Virginia Department of Transportation, public transit agencies, and school districts. The Company is also a partner in the Mid-Atlantic Coalition, which is pursuing funding for the development and expansion of clean hydrogen infrastructure for the Mid-Atlantic Hydrogen Hub.

Importantly, the Company does not intend to limit its evaluation of IIJA funding opportunities to a one-time review of the programs. Instead, the Company intends to continually review available IIJA opportunities over the law's five-year funding window. The Company is also ensuring that the SCC and NCUC stay informed of the Company's progress in taking advantage of IIJA opportunities, including by participating in relevant dockets (SCC Case No. PUR-2022-00180 and NCUC Docket No. M-100, Sub 164).

1.3 Severe Weather Events

Since 2020, severe weather events across the country have highlighted the vulnerability of the electric grid to natural threats, from a generation, transmission, and distribution perspective.

In December 2022, the effects of Winter Storm Elliott set a new demand peak for the DOM Zone and emphasized certain system planning considerations for the future. The weather on December 23, 2022, was unprecedented for that time of year in Virginia and North Carolina, with a severe temperature drop and resulting spike in load during a holiday weekend. A record-breaking plunge of 29 degrees over 12 hours surpassed the previous PJM record of a 22-degree drop during the 2014 Polar Vortex. As cold weather gripped the PJM region and power demand spiked, generators across the PJM system experienced high levels of forced generation outages—an unanticipated failure of all or part of a specific generator to perform. Approximately 70% of the outages were natural gas resources, likely driven by lack of fuel supply, lack of fuel purchases, or gas pipeline pressure challenges. PJM implemented emergency procedures, including calls for synchronized reserves, a Maximum Generation Emergency Action, and a call on demand response resources to keep the system operating in a reliable manner. Generation outages expanded further, and by the morning peak of December 24, 2022, PJM was missing approximately 46,000 MW of its generation fleet.

The Company's generation fleet performed well during Winter Storm Elliott, but the Company's natural gas-fired generation fleet experienced some limitations related to upstream pipeline pressure issues and units returning from outage as it related to the natural gas supply market for the four-day holiday weekend. Namely, intra-day natural gas supplies were insufficient and scarce, beyond supplies traded and scheduled on the pipelines, in the day ahead market (Friday, December 23). Many of the Company's dual-fueled units burned backup fuel oil due to economics and limited gas supply.

Winter Storm Elliott highlighted the importance of gas generators receiving sufficient and timely electric price signals, such that enough fuel can be purchased and scheduled in advance of the generation need. A disproportionate reliance on intra-day gas supplies is not sustainable during peak generation demand periods and highlights the importance of supplies or services that augment flowing gas supply. Options to reduce this risk include pipeline storage, liquified natural gas ("LNG"), peaking supply options, and on-site alternative fuels. The Company is evaluating these options. Nuclear, oil, and coal units were essential to reliable operations. The event highlighted the need for dispatchable generation, especially during the winter, the need for backup fuel and sufficient ancillary commodities (*e.g.*, ammonia or demineralized water) on site, and the risk of relying too heavily on market purchases or PJM Day Ahead awards during extreme weather.

While the PJM system was able to maintain reliable operations throughout this event, operating reserves were very limited. Utilities in Tennessee and North Carolina experienced rolling blackouts. Both PJM and the Federal Energy Regulatory Commission ("FERC") are conducting investigations, and the Company will follow the results closely.

In addition to evaluating options to improve generation availability, through its Grid Transformation Plan, the Company will continue to strategically invest significantly into strengthening electric distribution infrastructure, improving communications and controls, and proactively maintaining the rights-of-way that comprise and provide access to Company facilities. These investments will create a more resilient grid, improve reliability, and offer faster recovery after severe weather events. In January 2022, Winter Storm Frida impacted large areas of central and northern Virginia. Frida created an opportunity for the Company to observe the benefits of recent mainfeeder hardening efforts on affected infrastructure in central Virginia. The Company observed fewer outages and less significant damage on impacted facilities that had been hardened compared to those that had not yet been hardened.

1.4 Small Modular Reactors

As a carbon-free complement to renewable energy generation, nuclear generation provides a reliable and clean source of energy. Nuclear power thus remains a fundamental component of the clean energy transition to net zero emissions and a necessary resource to maintain reliability and affordability. SMRs provide a promising future supply-side resource option.

SMRs are a classification of nuclear reactors designed to produce up to 300 MW of electricity per reactor. Their modular nature allows for portions of the plant to be factory-fabricated and delivered to the site, improving construction quality and reducing construction timelines. Design improvements to SMRs have reduced the safety risks associated with traditional nuclear technology, and when coupled with their small size and modular construction process, make it possible to locate SMRs on a wide variety of sites, including brownfield sites (*e.g.*, retired fossil-fuel generation sites), existing nuclear power generation sites, other industrial areas, and areas closer to the electric demand. Such sites could be helpful in utilizing existing transmission infrastructure and providing a just transition for the local workforce.

Among the key benefits and improvements of SMRs over traditional nuclear technology is the increased use of passive safety systems. Passive safety systems rely on natural forces, such as gravity, pressure differences, or natural heat convection to accomplish safety functions without the need for operator action or a power source. This results in a power plant that is simpler, has less equipment, and does not require an emergency source of power. The fabrication of SMRs includes the repeat production of modular assemblies, incorporating a variety of components to a consistent design, reducing cost and time for production, and thus making the SMRs scalable.

Another key advantage of SMRs is their capability to produce electricity around the clock, providing reliability and stability to the electric grid. The SMR designs being developed are also expected to be dispatchable, meaning that they will be able to ramp up and down to meet demand or complement the Company's generation resources within timeframes comparable to natural gas-fired combined-cycle facilities, thus providing another resource to ensure that the system remains reliable and resilient for the Company's customers into the future.

Although this technology has not yet been deployed at scale, SMR design activities and regulatory licensing are accelerating both domestically and abroad. The Nuclear Regulatory Commission ("NRC") has engaged in varying degrees of pre-application activities with several SMR reactor designers and license applicants. In 2022, the NRC voted to certify the first SMR design in the United States, with final certification issued in early 2023. Other designs are expected to be approved over the next several years. Additionally, there are numerous utilities domestically and internationally that have announced intentions to deploy SMRs, which will contribute to the acceleration of development activities.

The Company plans to continue evaluating the feasibility, operating parameters, and costs of SMRs and will update modeling assumptions related to SMRs in future filings. Potential cost reductions relative to the assumptions reflected in the 2023 Plan may be realized as the design of SMRs matures and as anticipated construction schedules are established. Based on updated capital, operating and maintenance costs, continued progress of licensing timelines, and new policy initiatives or legislative changes, it is conceivable that the deployment of SMRs could be further accelerated by the Company, with the first SMR being placed in service within a decade.

1.5 Federal Interconnection Queue Reform

In early 2021, PJM announced a pause in its generation queue study process due to the backlog of queue projects waiting on final interconnection service agreements ("ISA"). In conjunction with this queue pause, PJM started a stakeholder process—the Interconnection Process Reform Task Force—to develop a new interconnection queue analysis process that would accommodate the integration of large numbers of renewable energy projects within the transmission system. This new queue study process was approved by PJM's stakeholders in May 2022; PJM filed for regulatory approval with FERC in June 2022 and expects to start the new process in the third quarter of 2023. This new process will eliminate PJM's current serial study process under which a reliability study is completed for each specific interconnection request, typically representing one project, and then all costs related to any necessary network upgrades fall on the developer of that one project even though other projects on the same feeder may contribute toward the need for the network upgrade. Under the proposed new process, all projects located on the same feeder are placed in one cluster for the reliability study and cost allocation analysis. Cost allocation for any identified network upgrades will remain within the cluster under study. Once the transition to this new process is complete, the new study process is projected to take less than 24 months from start to finish, which includes the execution of final ISAs. Some projects currently in the queue are eligible to be "fast tracked," but the ISAs for other potential projects may be delayed.

Separate from PJM's initiatives related to its interconnection queue, FERC issued a notice of proposed rulemaking in June 2022 to address the significant backlogs in interconnection studies across the country affecting more than 1,400 gigawatt ("GW") of new generation as of 2021. The FERC notice is proposing to implement a first-ready served queue cluster study process, improved interconnection queue processing speed, updated modeling and performance requirements for system reliability, and technological advancements to the interconnection process. FERC is also proposing that the North American Electric Reliability Corporation ("NERC") develop a benchmarking planning case for extreme weather events and that transmission providers develop corrective action plans when performance requirements are not met. FERC is proposing this change to address several extreme weather events that initiated the load shedding process, resulting in loss of power to customers.

Queue reform at the federal level will help to reduce the number of speculative projects submitted to the interconnection queue and evaluate reliability and transmission network upgrade expenses over a portfolio of projects. However, it is possible that delays in construction timelines may impact the Company's existing unit retirement assumptions and new generation additions in future filings.

1.6 Commodity Price and Cost Assumptions

Over the past 24 months, the United States has experienced high volatility in fuel and energy prices, more extreme weather events, supply chain constraints, and federal interconnection queue reform. These current circumstances highlight the need for resource diversity and dispatchable generation, as well as caution against retiring existing resources until the Company is certain it can reliably meet demand with newer technologies.

Construction costs for new resources also reflect market changes over the same period affected by record levels of inflation and global supply chain disruptions that are placing upward pressure on material and commodity costs. The result is a material increase in overall build costs, particularly for solar, onshore wind, and storage resources.

For modeling purposes, all cost and planning assumptions were included in the modeling as of March 15, 2023.

1.7 Virginia REC Market

The VCEA instituted a mandatory RPS Program in Virginia under which the Company must meet annual requirements for the sale of renewable energy based on a percentage of non-nuclear electric energy sold to retail customers in the Company's service territory, starting at 14% for the 2021 compliance year and increasing to 100% in compliance year 2045 and beyond. In years 2021 to 2024, the Company may use renewable energy certificates ("RECs") for RPS Program compliance originating from renewable energy facilities located within the PJM region. Beginning in 2025, 75% of the RECs used by the Company for RPS Program compliance must come from resources located in Virginia, with additional limitations on the type of facilities that qualify for compliance. Additionally, of the required percentage in each compliance year, 1% of the RECs must be from certain DERs located in Virginia with a nameplate capacity of 1 MW or less.

REC prices within existing PJM REC markets have risen since the enactment of the VCEA, in part because of the increased demand for RECs to comply with the mandatory RPS Program. The mandatory RPS Program will also result in the establishment of a new Virginia REC market because of the requirement for the Company to retire a significant number of RECs from Virginia-sited renewable energy facilities beginning in 2025. Although a market for Virginia in-state RECs has not fully developed, the 2023 Plan includes a Virginia REC price forecast. Based on current market dynamics, the price for RECs in the Virginia REC market will likely be equal to or higher than the PJM REC market price.

From a long-term planning perspective, the Company has concerns that RECs eligible for RPS Program compliance will not be widely available for the Company's use unless new renewable energy resources are built, especially in Virginia. The majority of Virginia RPS eligible sources are registered for renewable portfolio standard compliance in multiple states. As a result, it is difficult to ascertain how many of these RECs will be needed by other entities for compliance in other jurisdictions. There is also a large and growing number of corporate buyers in the market who procure and retire RECs to meet their corporate sustainability goals; these RECs will not be part of available supply for the Company to meet the Virginia RPS Program requirements. The ability of other entities to bank eligible RECs in other jurisdictions further complicates an analysis of available REC supply in the market.

According to the Company's current estimates, the Company's need for RECs from eligible resources will grow from approximately 9 million in 2025 to approximately 47 million in 2035. In the absence of the two incumbent electric utilities in Virginia developing these resources—either through construction or acquisition by the utility or through incentivizing the construction by third-party developers through PPAs—it is unlikely that the necessary renewable energy development in Virginia would materialize to meet the RPS Program requirements. The development targets set forth in the VCEA seem to recognize as much by requiring the Company and Appalachian Power Company to petition the SCC for the necessary approvals to construct, purchase, or acquire a significant amount of solar and wind resources. Because the Virginia REC market is in its infancy, it is difficult to predict what the future REC supply will be. However, if the market does not develop and the REC market is undersupplied, the market price of RECs is likely to become the equivalent of the VCEA-imposed deficiency payment for supply and demand to be in equilibrium. The Company will continue to closely monitor the feasibility of future RPS compliance.

This year the Company adjusted the REC forecast to account for a growing volume of accelerated renewable energy buyer ("ARB") customers who meet their REC needs with contracts within PJM. Section 9.3, ***Accelerated Renewable Energy Buyers*** provides more details about these customers. Even with this adjustment, due to the significant load growth in the 2023 PJM Forecast, the Company is significantly short of the required RECs for RPS compliance in alternative plans A, B, and C as early as 2036. By the end of the Study Period, customers will be paying as much as $2 billion a year in deficiency payments, at a rate of more than $59 per megawatt hour ("MWh").

See Section 4.7.4, ***REC-Related Assumptions***, for details on the assumptions the Company made for modeling purposes for this 2023 Plan based on these concerns.

1.8 Distribution Grid Transformation

Electricity has become a basic need, vital to the country's economy, public safety, and way of life. Critical services and infrastructure increasingly rely on electricity, including homeland security, medical facilities, public safety agencies, state and local governments, telecommunications, transportation, and water treatment and pump facilities. The transportation industry is actively continuing its shift toward electrification of personal vehicles, fleets, and mass transit. Another vital resource powered by electricity is the internet, which drives commerce and everyday life. As society has grown more dependent on electricity, customers expect highly reliable service. The critical need for reliable electric service became even more acute in 2020, when life for many Americans—including commerce, education, and health—shifted to the home, and the internet, because of the pandemic. While service interruptions have always been an inconvenience, the safe, reliable, and consistent grid connectivity has never been more important than it is today.

In addition to the importance of reliable electric service, fundamental changes in the energy industry driven by the rise in DERs have prompted the need for utilities across the country to modernize their distribution grids. In response to this need, the Company prepared a comprehensive plan to transform its distribution grid in Virginia (the "Grid Transformation Plan") to meet the changing landscape of the energy industry while continuing to provide the reliable service that its customers expect and deserve. The Grid Transformation Plan was first presented to the SCC in 2018, and from the initial investments in grid transformation projects the Company has seen notable successes that have had a direct and positive effect on its customers.

The passage of time has validated the need for the Grid Transformation Plan. The Company has seen the shift toward DERs, with an 86% increase in executed interconnection agreements for solar interconnections through the Company's Virginia queue between year-end 2021 and year-end 2022, a 59% increase in net energy metering customers, and an approximately 50% increase in customers with EVs in the Company's Virginia service territory. In addition, major weather events and physical attacks on utility infrastructure continue to show that more work is needed to achieve the objectives of grid transformation.

See Section 8.3, *Grid Transformation Plan*, for a description of the successes of the Grid Transformation Plan to date and an overview of the next phase on investments currently pending before the SCC.

1.9 New and Developing Technologies

Dominion Energy's Innovation and Sustainable Technologies business unit continues to help guide the Company toward the clean future envisioned by Virginia and North Carolina. Some of the more promising new technologies being investigated are as follows:

- **Power Generation Technology with Carbon Capture and Sequestration.** Natural gas combined-cycle plants fitted with carbon capture and sequestration ("CCS") are being consistently modeled as a necessary component of a low-carbon electric generation portfolio. Models of low-carbon scenarios by the Intergovernmental Panel on Climate Change, the International Energy Agency, Bloomberg New Energy Finance, and others all show significant contributions from CCS in the electric generation sector. CCS would allow a significant amount of existing dispatchable generation to stay online, while significantly reducing the carbon emitted by these plants. Research is ongoing into the storage and commercial uses for captured carbon. This technology is not currently allowed under the VCEA, which requires the Company's carbon-emitting generators in Virginia to retire by 2045, barring a petition for relief due to reliability or security concerns.

- **Hydrogen.** Hydrogen is both a fuel and a carrier that can be used to store and transport energy. Opportunities exist in the production, transportation, and usage of hydrogen to support a clean energy future when produced from low- or no-carbon sources. Examples include the use of hydrogen to "co-fire" natural gas generation providing peaking support. Hydrogen produced using excess renewable energy that may result as increasing amounts of renewable generation resources are added to the grid and provides medium and long-term energy storage opportunities for later use in natural gas power plants.

- **Electric Vehicles as a Resource.** Electric vehicles are becoming more prolific in most forms of transportation. With EVs, new technologies and software are being developed to maximize the benefits of electrification, such as load shifting and other applications that complement renewable generation. For example, vehicle-to-grid ("V2G") technologies are being developed through which electricity stored in EV batteries can be fed back onto the grid to lower peak demand or to provide grid support. See Section 8.6, ***Electric School Bus Program***, for a discussion of the Company's Electric School Bus Program through which it seeks to explore V2G technology. A precursor to taking advantage of this resource is a modernized grid that has full situational awareness.

- **Renewable Natural Gas.** Renewable natural gas ("RNG") is derived from biomethane or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. RNG can thus be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, industrial applications, and transportation. Adding RNG as a source of natural gas generation reduces overall emissions and, in some cases, serves as a carbon offset. These sources may be expanded based on new technologies to capture RNG from untapped sources and in remote areas.

- **Continuous Improvement in Solar Output.** Solar technology improvements such as advanced trackers, bifacial modules, and other technologies continue to improve capacity, output, intermittency profiles, and operational efficiency of solar generation. As these technologies mature, these improvements—especially higher capacity factor improvements—could provide more carbon-free generation with potentially less land use.

- **Medium and Long Duration Energy Storage.** The need for energy storage will grow with the proliferation of intermittent generation. Storage technologies that are on the horizon include new and improved batteries, hydrogen, thermal storage, and mechanical storage. Of particular interest are recent strides in the non-lithium alternatives and long duration batteries, where several technologies have announced pilot projects with utilities across the nation. Progress in the piloting phase will support greater levels of commercialization. Medium and long duration storage can provide significant benefits to the grid during extended periods of high load or when other fuels may be in short supply. See Section 5.5.1, ***Supply-Side Resource Options***, for additional discussion of energy storage technologies.

- **Carbon Offsets.** There is a substantial and growing market in carbon offsets in the United States. Carbon offsets can be generated by any activity that compensates for the emission of CO_2 or other greenhouse gases ("GHGs"). These offsets are measured in carbon dioxide equivalents ("CO_2e") by providing for an emission reduction elsewhere. Because GHGs are widespread in Earth's atmosphere, there is a climate benefit from emission reductions regardless of where the reductions occur. If carbon reductions are equivalent to the total carbon footprint of an activity, then the activity is said to be "carbon neutral." Carbon offsets can be bought, sold, or traded as part of a carbon market. Carbon offsets, verified by third parties, are used in voluntary and compliance markets across the country. The Company is focused on decarbonizing as much as possible first without the use of offsets.

- **Direct Air Capture Technology.** This aspirational technology is an industrial process for large-scale capture of atmospheric CO_2. Direct air capture ("DAC") technology pulls in atmospheric air then, through a series of chemical reactions, extracts the CO_2 from it while returning the rest of the air to the environment. This is what plants and trees do every day as they photosynthesize, except DAC technology does it much faster, with a smaller land footprint, and delivers the CO_2 in a pure, compressed form that can then be stored underground or reused. The potential of the DAC technology is tied to systems where excess or curtailed renewable energy is available at a very low cost to power the industrial process that removes CO_2 from the air. Utilizing the captured CO_2 to develop other products provides additional support to this process. Captured CO_2 can be produced in a solid form for safe storage creating a "negative emissions" industrial scale process or can be paired with end-use applications such as CO_2 enhanced oil field recovery or development of synthetic fuels to provide carbon neutral transportation fuels.

- **Methane Pyrolysis.** Methane pyrolysis converts natural gas into hydrogen and carbon solid (such as high-quality graphite) using iron ore and other types of catalyst. The aim of the methane pyrolysis is to achieve savings by using existing natural gas infrastructure, as well as providing "clean" hydrogen with significantly lower CO_2 emissions. This "clean" hydrogen can then be used in a range of developing clean energy applications, including power generation. The graphite can be used in the production of lithium-ion batteries.

- **Fusion.** Fusion offers a potential long-term energy source based on a controlled thermonuclear fusion reaction by combining two nuclei to form a new nucleus, while releasing energy. Fusion reactors have been researched for decades, and history was made at the U.S. National Ignition Facility in 2022 when an inertial confinement laser-driven fusion machine produced a positive fusion energy gain factor—that is, more power output than input. There is an abundant fuel source for fusion energy, which produces no GHGs and does not generate used nuclear fuel. There are currently multiple companies working towards commercialization of various types of fusion energy technologies.

- **Advanced Analytics.** The economy is experiencing both a rapid increase in computing power and an explosive growth in data. Both trends will allow energy companies to manage the electric grid and aggregate resources in ways that they have not been able to do in the past, providing additional opportunities to reduce CO_2 emissions. A precursor to the use of this data is a modernized grid that gathers and aggregates data through advanced metering infrastructure ("AMI") and intelligent grid devices and incorporates a sophisticated distributed energy resource management system, for planning and operation of the electric grid from a systems perspective.

1.10 Other Legislative Developments

During its 2023 Regular Session, the Virginia General Assembly passed several pieces of legislation which bear mentioning from an integrated resource planning standpoint. For modeling purposes, the Company assumed all proposed legislation would be approved.

- **House Bill 1643 and Senate Bill 1121.** These bills establish that it is the policy of the Commonwealth to "encourage the capture and beneficial use of coal mine methane, defined as methane gas captured and produced from an underground gob area associated with a mined-out coal seam that would otherwise escape into the atmosphere." The Company is mindful of the report due by November 15, 2023, from the Virginia Department of Energy on avenues to accomplish this policy objective and reiterates its commitment to evaluate emerging supply-side energy resource alternatives. On March 24, 2023, Virginia Governor Youngkin signed both bills into law, with an effective date of July 1, 2023.

- **House Bill 1770 and Senate Bill 1265.** Among other things, these bills amend and reenact statutes governing the manner in which the SCC conducts reviews of the Company's rates for generation and distribution services. These provisions have no impact on the modeling which informs the Alternative Plans presented herein. However, relevant ratemaking provisions—including a requirement to combine a subset of rate adjustment clauses with the Company's costs, revenues, and investments for generation and distribution services and the potential securitization of certain deferred fuel costs—are reflected in the Virginia

Consolidated Bill Analysis. The bills also direct the SCC to utilize information from the Company's integrated resource plans or RPS Development Plans in discussing, within an existing annual report, "the reliability impacts of generation unit additions and retirement determinations," as well as the potential impact of such unit additions and retirements determinations on "the purchase of power from generation assets outside the Virginia jurisdiction to serve the [Company's] native load." On April 12, 2023, the Virginia General Assembly adopted a series of largely technical amendments to both bills proposed by Virginia Governor Youngkin; the bills thus became law as amended, with an effective date of July 1, 2023.

- **House Bill 2026 and Senate Bill 1231.** These bills eliminate a statutory requirement for the Company—barring a petition for relief on the basis that such requirement would threaten the reliability or security of electric service—to retire all biomass-fired electric generating units that do not co-fire with coal by December 31, 2028. Therefore, the timing of potential retirements for the Company's biomass generators would be determined as a part of the retirement analysis. The bills also provide that the environmental attributes associated with biomass units may be used to comply with RPS program requirements, subject to certain conditions. As a result of this bill, in all Alternative Plans, the biomass stations Altavista, Southampton, and Hopewell are assumed to remain online for the duration of the plans and all RECs generated during the Study Period are used for RPS compliance. Virginia Governor Youngkin has a 30-day window ending May 12, 2023, to either sign or veto the bills. If the Governor does not act on the bills within this timeframe, they will become law without his signature with an effective date of July 1, 2023.

- **House Bill 2275 and Senate Bill 1166.** These bills shift the filing deadline for future integrated resource plans to October 15 of the year preceding the SCC's biennial reviews of the Company's rates for generation and distribution services (*i.e.*, in 2024, 2026, and so on). The bills further require the Company to submit annual updates to its integrated resource plans by October 15 of the years in which it is subject to such biennial reviews (*i.e.*, in 2025, 2027, and so on). It is important to note that North Carolina still requires that full Plans and update filings be submitted to the NCUC by September 1 each year. In addition, the legislation directs the Company to "conduct outreach to engage the public in a stakeholder review process and provide opportunities for the public to contribute information, input, and ideas" when preparing future integrated resource plan filings. The Company will report on public outreach efforts to the SCC at the time of future filings, as directed by the legislation. On April 12, 2023, the Virginia General Assembly adopted amendments to both bills proposed by Virginia Governor Youngkin; the bills thus became law as amended, with an effective date of July 1, 2023.

- **House Bill 2305.** This bill requires the Company to demonstrate, as part of a petition for a certificate of public convenience and necessity ("CPCN"), that certain proposed solar facilities were subject to competitive procurement or solicitation. On March 27, 2023, Virginia Governor Youngkin signed the bill into law, with an effective date of July 1, 2023.

- **House Bill 2444 and Senate Bill 1441.** These bills amend and reenact statutory language establishing that "the construction or purchase by a public utility of one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters and interconnected directly into the Commonwealth, with an aggregate capacity of up to 5,200 megawatts" is in the public interest. Specifically, the legislation accelerates the time horizon of this public interest declaration from December 31, 2034 to December 31, 2032. In Alternative Plans B and D, the Company build plan reflects the second offshore wind project fully operational by January 1, 2033. Virginia Governor Youngkin has a 30-day window ending May 12, 2023, to either sign or veto the bills. If the Governor does not act on the bills within this timeframe, they will become law without his signature with an effective date of July 1, 2023.

- **HB 2482 and SB 1541.** These bills direct the SCC to issue its final order for CPCN regarding projects identified by PJM as part of Baseline Project b3718 no later than 270 days after the filing date. For such projects filed prior to January 1, 2023, the bills direct the SCC to issue its final order within 90 days of the bills' effective date. Such approvals would not substantially change the outlook for the Company's need to import capacity and energy—all Alternative Plans presented herein contemplate a significant expansion of import capability. The Company therefore welcomes any developments which expedite deployment of new electric transmission infrastructure. On March 24, 2023, Virginia Governor Youngkin signed both bills into law, with an effective date of July 1, 2023.

- **Senate Bill 1477.** This bill authorizes the Company to establish an offshore wind affiliate for the purpose of securing a noncontrolling equity financing partner for the commercial-scale Coastal Virginia Offshore Wind ("CVOW") project, subject to SCC approval. The Company would retain responsibility to construct and operate the project irrespective of such approval—therefore, the legislation does not affect how the Company models the project's expected capacity or energy output. On March 24, 2023, Virginia Governor Youngkin signed the bill into law, with an effective date of July 1, 2023.

- **Senate Bill 1323.** This bill requires the SCC to establish annual energy efficiency savings targets for the Company's customers who are low-income, elderly, disabled, or military veterans. In establishing such targets, the SCC must seek to optimize energy efficiency and the health and safety benefits of utility energy efficiency programs. The bill requires the Company to make best efforts to coordinate such energy efficiency programs with any health and safety upgrades provided through energy efficiency programs authorized by provisions of the Code of Virginia, when reasonably feasible to do so and at the Company's sole discretion. On March 27, 2023, Virginia Governor Youngkin signed the bill into law, with an effective date of July 1, 2023.

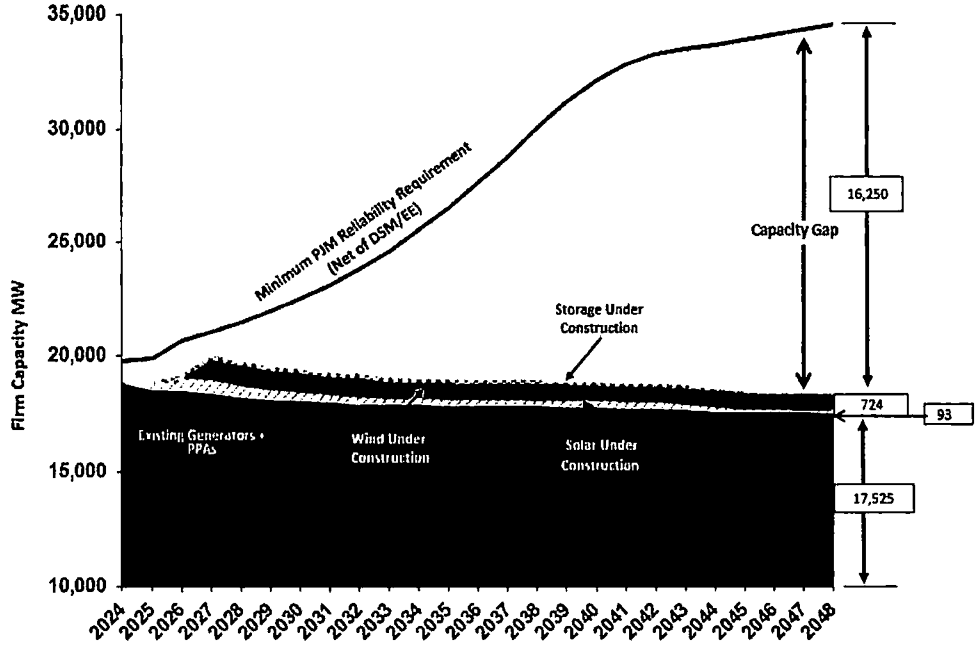
Chapter 2: Results of Integrated Planning Process

This chapter presents the results of the integrated planning process, including the Company's current positions, the Alternative Plans presented to meet the future needs of the Company's customers, the net present value ("NPV") of each Alternative Plan, and sensitivities on the Alternative Plans. This section also includes the results of the reliability analysis associated with the Alternative Plans and the results of a Virginia bill analysis.

2.1 Capacity, Energy, and REC Positions

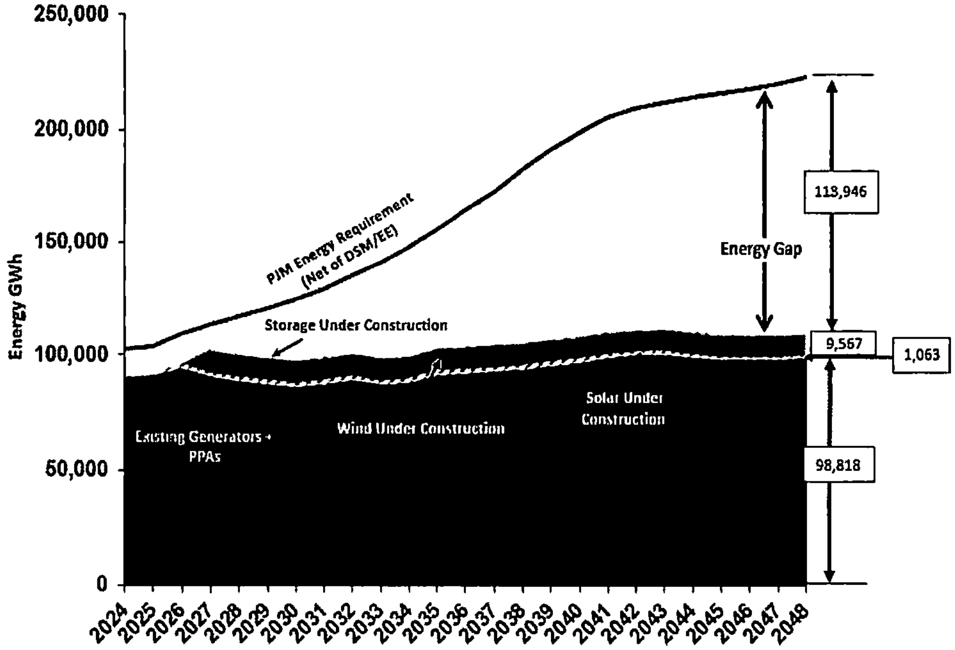
Figures 2.1.1, 2.1.2, and 2.1.3 represent the Company's current capacity (summer), energy, and REC positions under the Virginia RPS Program using unit retirement assumptions in Alternative Plan B.

Figure 2.1.1 - Current Company Summer Capacity Position with Plan B Retirement Assumptions (2024 to 2048)



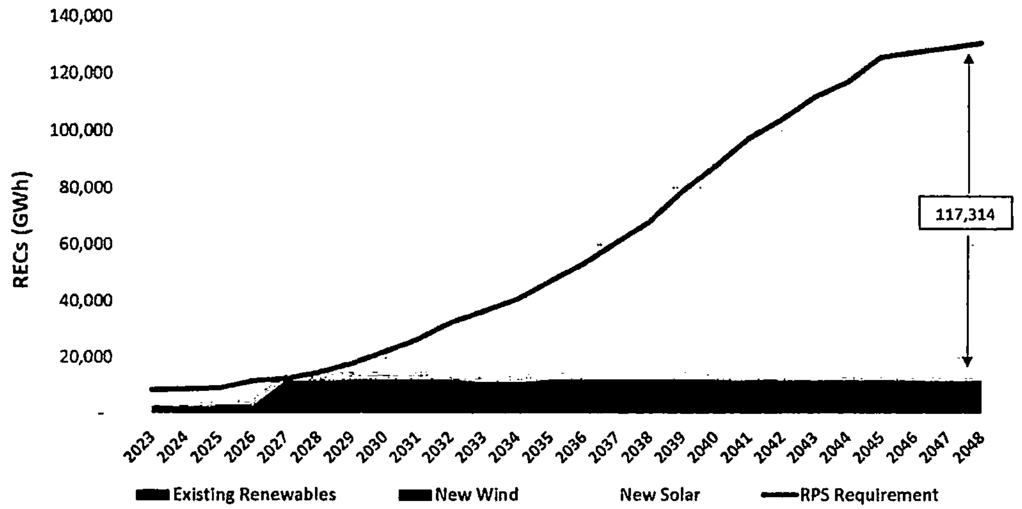
Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency.

Figure 2.1.2 – Current Company Annual Energy Position with Plan B Retirement Assumptions (2024 to 2048)



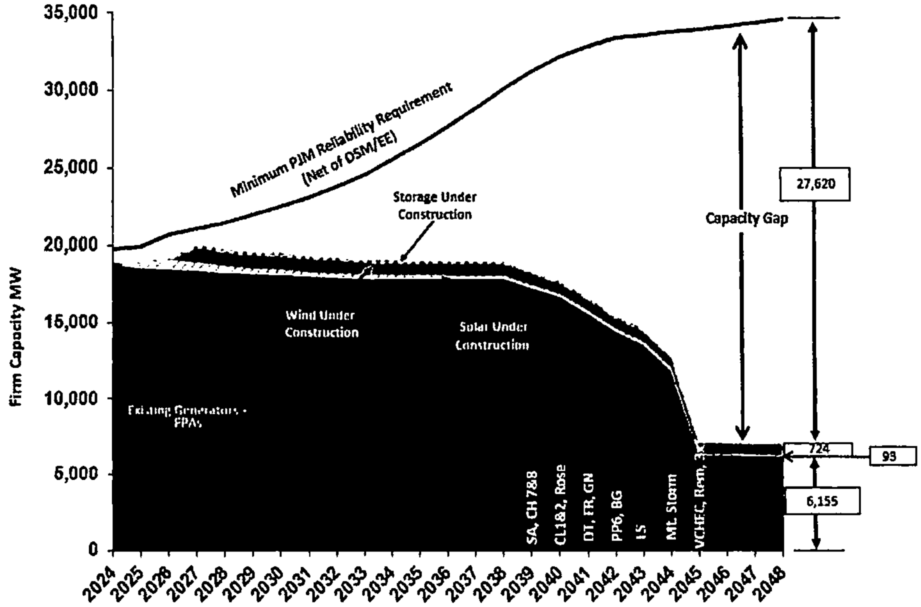
Notes: "PPAs" = power purchase agreement; "DSM" = demand side management "EE" = energy efficiency.

Figure 2.1.3: Current Company REC Position under Virginia RPS Program with Plan B Retirement Assumptions (2023 to 2048)



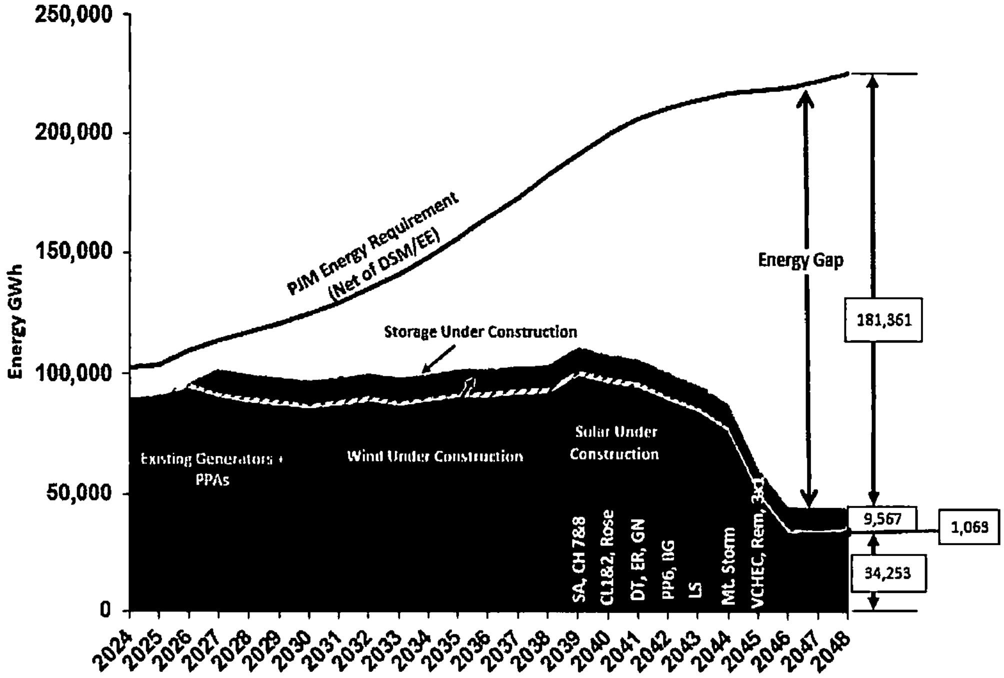
Figures 2.1.4, 2.1.5, and 2.1.6 represent the Company's current capacity (summer), energy, and REC positions under the Virginia RPS Program using unit retirement assumptions in Alternative Plan D.

Figure 2.1.4 - Current Company Summer Capacity Position with Plan D Retirement Assumptions (2024 to 2048)



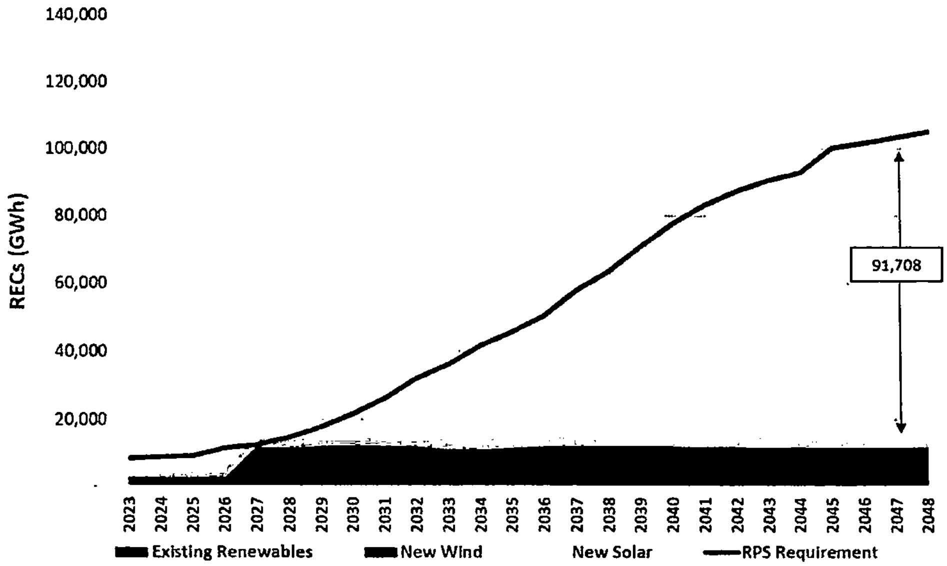
Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

Figure 2.1.5 - Current Company Annual Energy Position with Plan D Retirement Assumptions (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

Figure 2.1.6: Current Company REC Position under Virginia RPS Program with Plan D Retirement Assumptions (2023 to 2048)



Part 2

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

Case Number (if already assigned)	PUR-2023-00066
Case Name (if known)	Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.
Document Type	APLA
Document Description Summary	2 of 6 - 2023 Integrated Resource Plan of Virginia Electric and Power Company

Total Number of Pages	45
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The charts above show that both Alternative Plans B and D show a significant need for capacity, energy, and RECs throughout the Study Period. Plan B has a REC deficiency starting in 2039, while Plan D shows significant additional capacity and energy need due to unit retirements.

2.2 Alternative Plans

The 2023 Plan presents alternative paths forward for the Company to meet the future capacity and energy needs of its customers, as well as applicable requirements for procuring and retiring RECs under the Virginia RPS Program. Notably, planning work remains ongoing and necessary to test the grid under different conditions to ensure system reliability and security in the long term.

The Company's options for meeting customers' future capacity and energy needs are: (i) supply-side resources, (ii) demand-side resources, and (iii) market purchases. A balanced approach—which includes the consideration of options for maintaining and enhancing rate stability, increasing energy independence, promoting economic development, incorporating input from stakeholders, and minimizing adverse environmental impact—will help the Company meet growing demand while protecting customers from a variety of potential challenges.

The Company presents five Alternative Plans designed to meet customers' needs in the future under different scenarios, which were designed using constraint-based least-cost planning techniques and proven technologies:

- Plan A: This Alternative Plan presents a least-cost plan that meets only applicable carbon regulations and the mandatory Virginia RPS Program. The Company presents this Alternative Plan in compliance with prior SCC and NCUC orders and for cost comparison purposes only. For Plan A, the Company did not force the model to select any specific resource and did not exclude any reasonable resource. Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs and allowed the model to select the retirement dates for existing units on a least-cost optimization basis without regard for other factors that the Company considers when evaluating unit retirements. It is important to emphasize that Alternative Plan A does not meet the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. The Company does not consider Plan A as a true alternative path forward based on these concerns, as well as the over-reliance on third-party solar PPAs to meet customer needs, which comes with risks related to accountability and project execution. It is worth noting that even in Plan A, where all of the Company's existing resources stay online, a significant amount of new development is required to meet growing customer capacity and energy needs.

- Plan B: This Alternative Plan includes the significant development of solar, wind, and energy storage resources envisioned by the VCEA. Plan B preserves existing generation resources and adds an additional 2.9 GW of combustion turbine ("CT") generation to address future system reliability, stability, and energy independence issues. This allows the Company to maintain reliability while continuing to develop extensive renewable generation. Over the Study Period, this Alternative Plan includes the development of nearly 19 GW of additional solar capacity, approximately 2.6 GW of additional offshore wind capacity, 0.6 GW of new onshore wind, approximately 5.1 GW of additional energy storage capacity, and approximately 1.6 GW of SMRs. Even with the preservation of existing generation, additional CT generation, and the significant development of renewable generation, Plan B requires an increase in capacity import limits beginning in 2039 and the purchase of over 4 GW of capacity in 2041 and beyond.

- Plan C: This Alternative Plan is like Plan B in preserving existing generation and adds CT generation to address future system reliability, stability, and energy independence issues, with identical assumptions regarding the retirement of existing Company-owned carbon-emitting generation. Plan C differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA.

- Plan D: This Alternative Plan uses similar assumptions as Plan B but retires all Company-owned carbon-emitting generation by the end of 2045, resulting in zero CO_2 emissions from the Company's fleet in 2046. In order to retire these units, the Company will need to build and buy significant incremental capacity to reliably meet customer load. Plan D shows the Company building approximately 3.4 GW of incremental solar, 4.6 GW of incremental energy storage, and 3.2 GW of incremental SMRs to meet this need when compared to Plan B. Even with the additional SMRs and the preservation of 970 MW of new CT generation, assumed hydrogen capable by 2045, along with a significant incremental increase in energy storage, Plan D results in the Company purchasing over 10.8 GW of capacity and 13 GW of energy in 2045 and beyond, raising concerns about system reliability and energy independence, including reliance on out-of-state capacity to meet customer needs. In addition, there is no guarantee that other states will maintain dispatchable generation that will be available for purchase when the Company needs incremental power. This will depend greatly on the energy policy and load growth in neighboring states. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan D approach to maintain system reliability.

- Plan E: This Alternative Plan is like Plan D in retiring all Company-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimized basis without regard for the development targets for solar, wind, and energy storage resources in Virginia established through the VCEA. Like Plan D, under Plan E the Company would need to build and buy significant incremental capacity to reliably meet customer load. Over time as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan E approach to maintain system reliability.

All Alternative Plans utilize the load forecast prepared by PJM; assume a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia; and assume Virginia exits RGGI before January 1, 2024.

Figures 2.2.1 through 2.2.5 show the build plans for each Alternative Plan. The resource additions shown in these figures are incremental to existing generation and approved generation under construction, including solar and storage projects from CE-1, CE-2, and CE-3; nuclear license extensions; and nearly 2,600 MW of offshore wind.

Figure 2.2.1: Alternative Plan A (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,300	-
2025	-	-	-	-	-	-	-	1,400	-
2026	-	-	-	-	-	-	-	1,800	-
2027	900	-	-	-	-	-	-	900	-
2028	900	-	-	260	-	-	-	1,300	-
2029	900	-	-	-	-	-	-	1,700	-
2030	900	-	-	-	-	-	-	2,200	-
2031	900	-	-	60	120	-	-	2,700	-
2032	900	-	-	-	-	1,740	-	1,800	-
2033	900	-	-	-	-	-	-	2,600	-
2034	900	-	-	60	210	485	-	2,700	-
2035	900	-	-	-	-	2,225	-	1,500	-
2036	900	-	-	-	210	485	-	1,800	-
2037	900	-	-	2,660	300	485	-	1,400	-
2038	900	-	-	-	210	485	-	2,000	-
15-Year Subtotal	**10,800**	**-**	**-**	**3,040**	**1,050**	**5,905**	**-**	**27,100**	**-**
2039	900	-	-	-	270	485	-	2,400	-
2040	900	-	-	60	240	485	-	2,600	-
2041	900	-	-	-	300	1,455	-	1,600	-
2042	900	-	-	-	300	485	-	1,400	-
2043	900	-	-	60	300	485	-	900	-
2044	900	-	-	-	300	-	-	900	-
2045	900	-	-	-	300	-	-	1,000	-
2046	900	-	-	60	300	-	-	1,100	-
2047	900	-	-	-	300	-	-	1,200	-
2048	900	-	-	-	300	-	-	1,300	-
25-Year Total	**19,800**	**-**	**-**	**3,220**	**3,960**	**9,300**	**-**	**41,500**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Figure 2.2.2: Alternative Plan B (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	210	390	15	-	-	-	-	700	-
2028	231	429	30	260	90	970	-	200	-
2029	231	429	45	-	120	-	-	600	-
2030	252	468	45	-	150	-	-	900	-
2031	315	585	111	60	180	-	-	1,300	-
2032	315	585	111	-	180	-	-	1,800	-
2033	315	585	111	2,600	240	-	-	1,600	-
2034	315	585	111	60	240	-	268	1,900	-
2035	315	585	114	-	270	485	-	2,100	-
2036	315	585	114	-	300	485	268	2,100	-
2037	315	585	114	60	300	485	-	2,300	-
2038	315	585	114	-	300	485	268	2,600	-
15-Year Subtotal	3,444	6,396	1,035	3,040	2,370	2,910	804	21,900	-
2039	315	585	-	-	180	-	-	3,500	-
2040	315	585	-	60	300	-	268	3,900	-
2041	315	585	-	-	300	-	-	4,400	-
2042	315	585	-	-	240	-	268	4,400	-
2043	315	585	-	60	300	-	-	4,400	-
2044	315	585	-	-	300	-	268	4,200	-
2045	315	585	-	-	300	-	-	4,300	-
2046	315	585	-	60	300	-	-	4,400	-
2047	315	585	-	-	300	-	-	4,400	-
2048	315	585	-	-	300	-	-	4,600	-
25-Year Total	6,594	12,246	1,035	3,220	5,190	2,910	1,608	64,400	-

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Figure 2.2.3: Alternative Plan C (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	315	585	-	-	-	-	-	600	-
2028	315	585	-	140	-	-	-	1,000	-
2029	315	585	-	-	-	-	-	1,500	-
2030	315	585	-	120	30	-	-	1,900	-
2031	315	585	-	60	300	-	-	2,300	-
2032	315	585	-	-	300	-	-	2,700	-
2033	315	585	-	-	300	1,455	-	1,800	-
2034	315	585	-	60	90	-	268	2,300	-
2035	315	585	-	2,600	300	-	-	2,200	-
2036	315	585	-	-	300	485	268	2,700	-
2037	315	585	-	60	300	485	-	2,700	-
2038	315	585	-	-	300	485	268	2,700	-
15-Year Subtotal	**3,780**	**7,020**	**-**	**3,040**	**2,220**	**2,910**	**804**	**28,200**	**-**
2039	315	585	-	-	300	-	-	3,500	-
2040	315	585	-	60	300	-	268	4,000	-
2041	315	585	-	-	300	-	-	4,500	-
2042	315	585	-	-	300	-	268	4,400	-
2043	315	585	-	60	300	-	-	4,400	-
2044	315	585	-	-	300	-	268	4,200	-
2045	315	585	-	-	300	-	-	4,300	-
2046	315	585	-	60	300	-	-	4,400	-
2047	315	585	-	-	300	-	-	4,400	-
2048	315	585	-	-	300	-	-	4,500	-
25-Year Total	**6,930**	**12,870**	**-**	**3,220**	**5,220**	**2,910**	**1,608**	**70,800**	**-**

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units.

Figure 2.2.4: Alternative Plan D (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas-Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	210	390	15	-	-	-	-	700	-
2028	231	429	30	260	90	970	-	200	-
2029	231	429	45	-	120	-	-	600	-
2030	252	468	45	-	150	-	-	900	-
2031	315	585	111	60	180	-	-	1,300	-
2032	315	585	111	-	180	-	-	1,800	-
2033	315	585	111	2,600	240	-	-	1,600	-
2034	315	585	111	60	240	-	-	2,200	-
2035	315	585	114	-	270	-	536	2,300	-
2036	315	585	114	-	300	-	536	2,600	-
2037	315	585	114	60	300	-	-	3,300	-
2038	315	585	114	-	300	-	536	3,800	-
15-Year Subtotal	3,444	6,396	1,035	3,040	2,370	970	1,608	25,100	-
2039	420	780	-	-	810	-	536	4,200	CH 7&8, SA
2040	420	780	120	60	900	-	536	4,400	CL 1&2, Rosemary
2041	420	780	120	-	900	-	536	4,800	DT, ER, GN
2042	420	780	120	-	900	-	536	5,200	PP6, BG
2043	420	780	120	60	900	-	536	5,000	LS
2044	420	780	120	-	900	-	536	5,600	Mt Storm
2045	420	780	120	-	900	-	-	10,800	3x1, VCHEC, Rem
2046	420	780	120	60	360	-	-	10,800	-
2047	420	780	120	-	360	-	-	10,800	-
2048	420	780	120	-	480	-	-	10,800	-
25-Year Total	7,644	14,196	2,115	3,220	9,780	970	4,824	97,500	11,399

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units; "CH 7&8" = Chesterfield Units 7&8 (gas); "SA" = South Anna; "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "3x1"= Greensville, Brunswick and Warren (gas); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas).

Figure 2.2.5: Alternative Plan E (Nameplate MW)

Year	Solar PPA	Solar COS	Solar DER	Wind	Storage	Natural Gas Fired	Nuclear	Capacity Purchases	Retirements
2024	-	-	-	-	-	-	-	1,100	-
2025	-	-	-	-	-	-	-	1,100	-
2026	-	-	-	-	-	-	-	1,600	-
2027	315	585	-	-	-	-	-	600	-
2028	315	585	-	140	-	-	-	1,000	-
2029	315	585	-	-	210	-	-	1,300	-
2030	315	585	-	120	300	-	-	1,400	-
2031	315	585	-	60	300	-	-	1,800	-
2032	315	585	54	-	300	-	-	2,200	-
2033	315	585	120	-	300	-	-	2,700	-
2034	315	585	-	60	300	970	-	2,300	-
2035	315	585	-	2,600	300	-	-	2,200	-
2036	315	585	-	-	300	-	268	2,700	-
2037	315	585	-	60	300	-	268	3,300	-
2038	315	585	120	-	300	-	536	3,800	-
15-Year Subtotal	3,780	7,020	294	3,040	2,910	970	1,072	29,100	
2039	420	780	120	-	900	-	536	4,100	CH 7&8, SA
2040	420	780	120	60	900	-	536	4,300	CL 1&2, Rosemary
2041	420	780	120	-	900	-	536	4,800	DT, ER, GN
2042	420	780	120	-	900	-	536	5,200	PP6, BG
2043	420	780	120	60	900	-	536	4,900	LS
2044	420	780	120	-	900	-	536	5,600	Mt Storm
2045	420	780	120	-	900	-	-	10,800	3x1, VCHEC, Rem
2046	420	780	120	60	360	-	-	10,800	-
2047	420	780	120	-	750	-	-	10,500	-
2048	420	780	120	-	30	-	-	10,800	-
25-Year Total	7,980	14,820	1,494	3,220	10,350	970	4,288	100,900	11,399

Notes: "COS" = cost of service; "PPA" = power purchase agreement; "DER" = distributed energy resources, whether Company-owned or PPA; "Wind" includes both on and offshore wind units; "CH 7&8" = Chesterfield Units 7&8 (gas); "SA" = South Anna; "CL1&2" = Clover Units 1 & 2 (coal); Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "3x1"= Greensville, Brunswick and Warren (gas); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas).

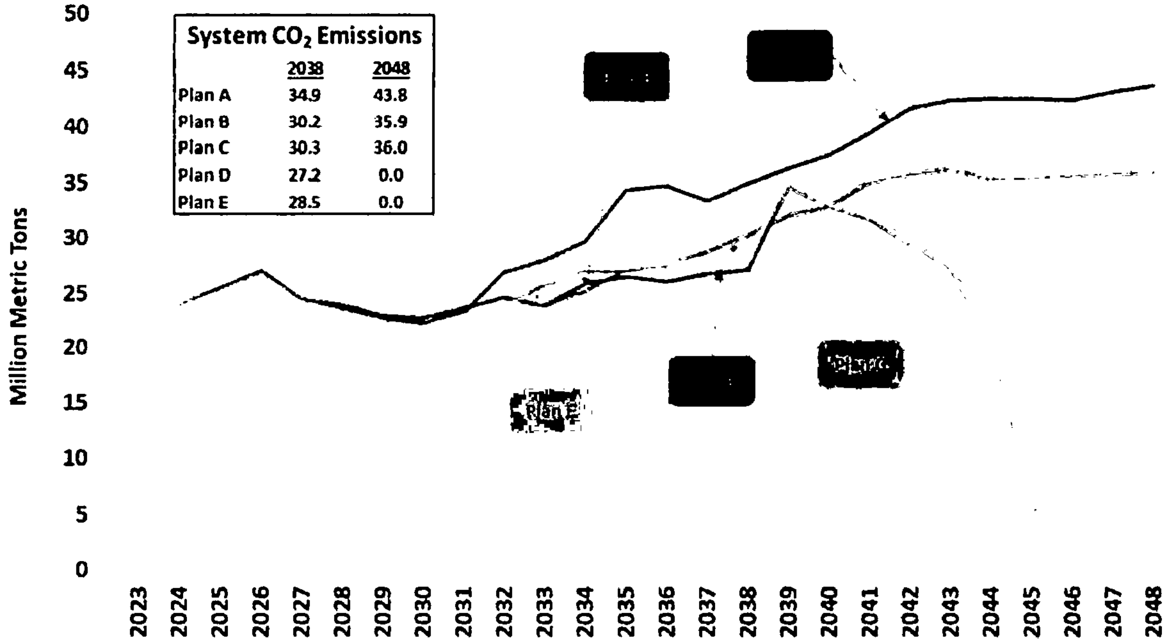
Charts showing the capacity (summer), energy, and REC positions assuming the build plans shown in each Alternative Plans are provided in Appendix 2A. Winter capacity charts for each Alternative Plan are provided in Appendix 5T. Solar resources provide little capacity for winter peaks, while wind, nuclear and fossil resources produce more in the winter than in the summer. A diverse resource mix will ensure that the Company is able to meet the needs of customers during extreme weather events in both the summer and winter months.

The SCC directed the Company to consider market purchases during the winter from the PJM wholesale market or from merchant generators located in the DOM Zone. The Company is concerned that overreliance on the market for purchases could present issues if other states within PJM build significant amounts of solar generation and those zones expect the market to provide energy at the same time the Company is expecting that energy (*e.g.*, extended cloudy winter periods). If that were to become reality, either energy shortages or extreme price spikes would occur. Concerning purchases from merchant generators located within the DOM Zone, those generators would likely be needed to meet the non-DOM LSE load within DOM Zone~~, which is also winter peaking~~. The merchant generators located within the DOM Zone are likely also committed to PJM or specific customers. That said, this is not public information, making it difficult for the Company to incorporate those potential resources into its planning. See Appendix 2B for the capacity-related information directed by the SCC.

All Alternative Plans show that a growing capacity and energy need will require a diverse mix of resources and an increased reliance on market purchases, even under normal weather conditions and with very few unit retirements. These plans demonstrate that solar, wind, and storage will be the majority of the Company's generation development over the next fifteen years. Until new zero carbon dispatchable generation options are developed or reach commercial viability, gas units are among the most affordable and reliable options for new generation that can quickly adjust output with changes in intermittent output. With normal weather modeling in Plans A, C, and E these combustion turbine facilities were economically selected by the model by 2035 at the latest. However, to address energy and capacity needs during more extreme weather scenarios, especially in the winter, the Company included 970 MW of new CT generation as early as 2028 in Plans B and D. These units will be capable of blending hydrogen in the future and critical to meeting grid reliability needs much sooner than 2035.

Figure 2.2.6 shows projected CO_2 emissions from the Company's fleet for the duration of the Study Period. Due the changes in retirements, as well as higher capacity factors for the Company's existing generators driven by the higher 2023 PJM Load Forecast, carbon emission projections are increasing. Both the build plans and the carbon projections in all five Alternative Plans are similar for the first ten years. While Plans D and E show no Scope 1 emissions by 2045, the level of purchased power required to make the necessary retirements possible would have a Scope 3 emissions impact. ICF Resources, LLC ("ICF") forecasts show gas remaining as the margin generator throughout the Study Period. Through the energy transition, the Company will continue to monitor PJM Margin Emissions rates and evaluate the regional emissions impacts of running existing units versus relying on purchasing power from the market.

Figure 2.2.6 – System CO_2 Output from Company Fleet for Alternative Plans (based on current technology)



2.3 Reliability Analyses of Alternative Plans

The Company completed a high-level assessment of the potential reliability of the Company's transmission system under the build plans shown in Alternative Plans A through E, with the goal of identifying any potential reliability concerns. A significant factor in future transmission system reliability is the retirement of synchronous generation facilities. Based on the complexity and the time it takes to complete this type of analysis, the Company used preliminary versions of Alternative Plans A through E in this 2023 Plan, the 2022 PJM Load Forecast, and the 2022 model series for 2035 and 2045 for the reliability studies. Given the significant increase in load in the 2023 PJM Load Forecast compared to the 2022 PJM Load Forecast, the potential reliability concerns identified are likely understated. The Company provides a summary of its assessment here, with additional details provided in Chapter 7:

- Plan A: The Company does not have significant transmission system reliability concerns under the build plan shown in Plan A. While Plan A includes a significant amount of new intermittent solar generation, Plan A also maintains the majority of the Company's existing fleet of synchronous generation facilities and constructs additional quick-start and dispatchable combustion turbines, both of which would help the transmission system maintain reliability and continue to run similarly to how it runs today.

- Plan B: The Company does not have significant transmission system reliability concerns under the build plan shown in Plan B. Plan B includes a significant amount of new intermittent renewables compared to Plan A. However, Plan B also maintains a large amount of the Company's existing fleet of synchronous generation facilities and includes the addition of new SMRs. The combination of existing generation and the new SMRs help the transmission system maintain reliability and continue to run similarly to how it runs today. Notably, Plan B incorporates approximately $6 billion of transmission infrastructure to account for the higher level of imports needed to meet demand by 2040.

- Plan C: The Company does not have significant transmission system reliability concerns under the build plan shown in Plan C, as it only varies from Plan B minimally.

- Plan D: The Company has system reliability concerns under the build plan shown in Plan D due to the retirement of all carbon-emitting units—the traditional synchronous generators relied on for system reliability—by the end of 2045. The Company's analysis showed suboptimal primary frequency and inertia response following the retirement of a large synchronous generation. The average fault current over the Company system decreased when compared to Plans A, B, and C. Notably, Plan D incorporates approximately $10.9 billion of transmission infrastructure to account for the higher level of imports needed to meet demand.

- Plan E: The Company has the same system reliability concerns under the build plan shown in Plan E, which varies from Plan D minimally.

2.4 NPV Results

The Company evaluated the Alternative Plans to compare the NPV utility costs for each build plan over the Study Period. Figure 2.4.1 presents these NPV results on the "Total System Costs" line, as well as the estimated NPV of proposed investments in the Company's transmission and distribution systems, broken down by specific line item.

Figure 2.4.1 – NPV Results

($B)	Plan A	Plan B	Plan C	Plan D	Plan E
Total System Costs	$88.5	$100.2	$99.7	$108.8	$105.8
Grid Transformation Plan (Net of Benefits)	$(1.6)	$(1.6)	$(1.6)	$(1.6)	$(1.6)
Strategic Underground Program	$0.7	$0.7	$0.7	$0.7	$0.7
Transmission	$22.2	$28.4	$28.4	$33.1	$33.1
Total Plan NPV	**$109.7**	**$127.7**	**$127.2**	**$140.9**	**$138.0**
Plan Delta vs. Plan A	$ -	$ 18.0	$17.5	$31.2	$ 28.3

Notes: As previously ordered by the SCC, this figure includes incremental cost estimates associated with transmission and distribution investments. All costs are estimates and will vary based on the actual generation, transmission, and distribution infrastructure developed to meet customer needs. (1) Total system costs include the results from Figures 2.2.1 through 2.2.5 plus approved, proposed, future, and generic DSM, as applicable; costs related to environmental laws and regulations; renewable energy integration costs; and REC banking as discussed in Section 4.7.4, ***REC-Related Assumptions***. (2) All NPVs are calculated with a 6.52% discount rate. (3) Numbers may not add due to rounding.

2.5 Virginia Consolidated Bill Analysis

The Company completed a consolidated bill analysis for each Alternative Plan presented in the 2023 Plan. This analysis encompasses three different customer classes and spans 2019 through 2035.

The Company calculated projected bills for each customer class under each Alternative Plan based on requirements set by the SCC ("Directed Methodology"). These requirements direct that the Company use constant class allocation factors across time and no sales growth, either at the system or class level, in its calculations. As discussed in prior proceedings, the Company believes that this methodology results in overstated bill projections because it does not reflect anticipated growth in sales over the period on which each build plan is based.

Given these concerns with the Directed Methodology, the Company has also calculated projected bills under each Alternative Plan using a forecasted system and class sales growth and the associated class allocation factors ("Company Methodology").

The electric bill of the Company's typical residential customer in Virginia (*i.e.*, one that uses 1,000 kWh per month) was $122.66 as of December 31, 2019. As of May 1, 2020, this typical bill was $116.18, with the decrease largely attributable to a significant reduction in the fuel factor. Figure 2.5.1 presents the summary results of typical residential customer bill projections under both the Company Methodology and the Directed Methodology based on Alternative Plan B for 2030 and 2035.

Figure 2.5.1 shows that, when using the Company Methodology and a baseline of May 1, 2020, the typical residential customer's bill is expected to increase at a compound annual growth rate ("CAGR") of 2.6% through 2035. When using the Company Methodology and December 31, 2019, as the baseline, the projected increase in the typical residential customer's bill is approximately 2.2% on a compound annual basis.

As an additional point of comparison, in July 2008—the year following passage of the Virginia Electric Utility Regulation Act—the electric bill of the Company's typical residential customer in Virginia was $107.20. Using 2008 as the baseline, the projected CAGR for the typical residential customer bill through 2035 is approximately 1.8% using the Company Methodology.

Figure 2.5.1: Residential Bill Projection (1,000 kWh per Month)

	Plan B – Company Methodology (includes load growth)			Plan B – Directed Methodology (excludes load growth)		
	Projected Bill	CAGR Dec. 2019	CAGR May 2020	Projected Bill	CAGR Dec. 2019	CAGR May 2020
Dec. 31, 2019	$122.66			$122.66		
May 1, 2020	$116.18			$116.18		
Year End 2030	$167.34	2.9%	3.5%	$193.12	4.2%	4.9%
Year End 2035	$174.15	2.2%	2.6%	$235.40	4.2%	4.6%
Total Bill Increase (May 2020-2035)	$57.97			$119.22		

Note: Derived using the system resources selected in Alternative Plan B incorporating the Company Methodology for the purposes of the future billing analysis, including forecasted sales growth and forecasted class allocation factors.

The typical Company residential customer in Virginia (*i.e.*, one who uses 1,000 kilowatt-hours of electricity per month) pays $140.25 as of January 1, 2023, which on a per-unit basis is approximately 14.03 cents per kilowatt-hour ("¢/kWh"). This figure compares favorably to the national average (15.47¢/kWh) and the regional averages for the South Atlantic (14.04¢/kWh), Middle Atlantic (19.86¢/kWh), and New England (29.74¢/kWh) states as reported in the U.S. Energy Information Administration's ("EIA") electric power monthly release with data for January 2023.

2.6 Sensitivity Analyses

The Company conducted several sensitivities for this 2023 Plan to show the potential paths forward under different future conditions consistent with SCC and NCUC requirements. For all sensitivities, the Company re-optimized the build plans applying different assumptions.

First, the Company conducted sensitivities related to RGGI based on the uncertainty discussed in Section 5.2.3, ***Environmental Regulations***. The base assumptions for Alternative Plans A through E all use a commodity price forecast that assumes Virginia exits RGGI before January 1, 2024. For its sensitivity analyses, the Company used a commodity price forecast that assumes Virginia stays in RGGI and includes a RGGI-related cost adder on all Virginia carbon-emitting generators. Figure 2.6.1 compares the Alternative Plans under their base case assumptions with the Alternative Plan assuming Virginia stays in RGGI. As the table shows, it would be more expensive for customers if Virginia remains in RGGI, while making a negligible difference in the Company's carbon emissions.

Figure 2.6.1: 2023 Plan Sensitivities on Virginia in RGGI

Plan	NPV Total ($B)		Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	
	Base Plan	Va. in RGGI	Base Plan	Va. in RGGI
Plan A	$109.7	$111.5	43.8 M	43.5 M
Plan B	$127.7	$129.3	35.9 M	35.8 M
Plan C	$127.2	$129.1	36.0 M	35.9 M
Plan D	$140.9	$142.5	0	0
Plan E	$138.0	$139.7	0	0

Second, the Company conducted sensitivities using different load forecasts. As discussed above, Alternative Plan B utilizes the 2023 PJM Load Forecast. The Company increased and decreased the 2023 PJM Load Forecast by 5% to show the build plans under high and low load forecast scenarios. The Company also ran a sensitivity using the 2023 Company Load Forecast. Finally, the Company ran a sensitivity reflecting only approved energy efficiency programs as required by the SCC. Figure 2.6.2 shows the results of these sensitivities.

Figure 2.6.2: 2023 Plan Sensitivities on Load Forecast

	Plan B (PJM Load Forecast)	Plan B with PJM High Load Forecast	Plan B with PJM Low Load Forecast	Plan B with Company Load Forecast	Plan B with Approved Energy Efficiency
NPV Total ($B)	$127.7	$137.9	$110.2	$129.7	$127.8
Approximate CO_2 Emissions from Company in 2048 (Metric Tons)	35.9 M	39.2 M	34.5 M	38.7 M	38.6 M
Solar (MW)	10,875 15-yr 19,875 25-yr	10,875 15-yr 20,475 25-yr	10,875 15-yr 19,917 25-yr	10,875 15-yr 19,875 25-yr	10,875 15-yr 20,235 25-yr
Wind (MW)	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr	3,040 15-yr 3,220 25-yr
Storage (MW)	2,370 15-yr 5,190 25-yr	2,370 15-yr 4,170 25-yr	2,370 15-yr 4,050 25-yr	2,370 15-yr 5,040 25-yr	2,370 15-yr 5,370 25-yr
Nuclear (MW)	804 15-yr 1,608 25-yr	804 15-yr 1,608 25-yr	268 15-yr 536 25-yr	536 15-yr 1,340 25-yr	485 15-yr 1,940 25-yr
Natural Gas Fired (MW)	2,910 15-yr 2,910 25-yr	2,425 15-yr 2,910 25-yr	1,455 15-yr 2,910 25-yr	2,910 15-yr 2,910 25-yr	1,455 15-yr 2,910 25-yr
Retirements (MW)	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr	-- 15-yr -- 25-yr

Third, the Company ran input variations on Alternative Plan B to show the effect on NPV using a range of possible costs. The Company first ran a sensitivity using different commodity price forecasts. To provide sensitivities on fuel, energy, capacity, and REC prices, the Company used two commodity price forecasts produced by ICF—the High Fuel Price commodity forecast and the Low Fuel Price commodity forecast. See Section 4.4, ***Commodity Price Assumptions***, for a description of these forecasts and the interrelated nature of these commodity prices. The Company then ran a sensitivity that increased and decreased the projected capital construction costs of different resources by 10%. The Company also ran a sensitivity showing all solar resources at a projected design capacity factor instead of the lower of the design capacity factor or the three-year historical average capacity factor of the Company's existing solar fleet in Virginia. Figure 2.6.3 shows the summarized results of this group of sensitivities.

Figure 2.6.3: 2023 Plan Sensitivities on NPV Costs

Plan Description	NPV Total ($B)
Plan B	$127.7
Plan B: High Fuel Prices	$143.4
Plan B: Low Fuel Prices	$124.9
Plan B: High Capital Construction Costs	$134.7
Plan B: Low Capital Construction Costs	$124.0
Plan B: Solar Design Capacity Factor	$126.9

Chapter 3: Short-Term Action Plan

The short-term action plan provides the Company's strategic plan for the next five years (2024 to 2029). The Company plans to proactively position itself in the short-term to meet its commitment to clean energy for the benefit of all stakeholders over the long term. The Company also plans to continue its analyses on how to meet both its clean energy goals and the requirements of the VCEA while continuing to provide safe, reliable, and affordable service to its customers.

3.1 Generation

Over the next five years, the Company expects to take the following actions related to existing and proposed generation resources:

- File annual plans for the development of solar, onshore wind, and energy storage resources consistent with the requirements established by the VCEA, including related requests for approval of CPCNs and for prudence determinations related to PPAs;
- Complete construction of CVOW with a target in-service date of late 2026;
- Continue construction and begin operation of approved solar and storage projects;
- Meet targets under Virginia's mandatory RPS Program at a reasonable cost and in a prudent manner, and submit annual compliance certification to the SCC;
- Meet target under North Carolina's renewable energy portfolio standard at a reasonable cost and in a prudent manner, and submit its annual compliance report and compliance plan to the NCUC;
- Support ongoing NRC review of the subsequent license renewal application for North Anna Units 1 and 2;
- Continue development work for 970 MW of new gas-fired CTs, see Section 5.4.2, ***Combustion Turbines***;
- Begin development of a backup LNG facility to support reliable operations of the Company's Greensville Power Station and possibly other stations;
- Continue to make investments at existing generation units needed to comply with environmental regulations;
- Evaluate opportunities for uprates or increased capacity injection rights ("CIRs") at existing units;
- Continue to evaluate potential unit retirements or replacement of existing units in light of changing market conditions and regulatory requirements; and
- Continue to evaluate pilot energy storage projects associated with the battery storage pilot program established by the Grid Transformation and Securities Act of 2018 ("GTSA").

Appendices 3A and 3B provide further details on each generation project under construction and under development, respectively. The Company has not discontinued its pursuit of any potential supply-side resources over the short-term since the 2020 Plan, the projected dates and nameplate capacity in each year has simply shifted with actual development activity.

3.2 Demand-Side Management

Over the next five years, the Company will continue to identify and propose new, revised, or bundled DSM programs that work towards the spending targets of the GTSA and the energy savings targets of the VCEA in conjunction with the established DSM stakeholder process and the recommendations from the Company's long-term DSM plan. The Company is currently conducting an appliance saturation study and, once completed, will begin a new DSM market potential study in 2023, with results expected in early 2024.

In Virginia, the Company filed its Phase XI DSM application in December 2022, seeking approval of five new DSM programs (one of which is a pilot) and four new program bundles. The SCC is expected to issue its final order on the application in August 2023.

In North Carolina, the Company will continue its analysis of future programs and will file for approval in North Carolina for those programs that continue to meet Company requirements for new DSM resources and have been approved in Virginia, while also meeting the expectations of the NCUC regarding cost-effectiveness.

3.3 Transmission

Over the next five years, the Company will continue to assess its transmission system and construct facilities required to meet the needs of its customers. Generally, the Company anticipates transmission facilities will be needed to rebuild aging infrastructure, interconnect data center customers, address reliability criteria violations, and interconnect new renewable energy projects. Appendix 3C provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM. Appendix 7A lists the transmission lines under construction.

The Company will also continue its work to study the transmission system reliability needs resulting from the addition of significant renewable energy resources and the potential retirement of synchronous generator facilities, as discussed in Chapter 7.

3.4 Distribution

Over the next five years, the Company will continue to assess its distribution grid, adapt the distribution grid to meet the needs of a modernized system, and implement solutions and programs to meet the needs of its customers both today and in the future. Specifically, the Company expects to take the following actions related to its distribution grid:

- Continue implementing the Grid Transformation Plan, including initiatives to facilitate the integration of DERs, enhance distribution grid reliability, resiliency, and security, and improve the customer experience;
- Continue publishing hosting capacity maps for utility-scale DERs, net metering DERs, and transportation electrification;
- Explore the use of energy storage systems as non-wires alternatives for distribution grid support using a standardized screening process;
- Continue developing integrated distribution planning capabilities, including advancing load and DER forecasting capabilities;
- Continue its Strategic Undergrounding Program ("SUP");
- Continue to expand EV program offerings for customers;
- Continue to pilot vehicle-to-grid technology through the Electric School Bus Program;
- Continue to pilot battery energy storage systems ("BESS") as grid support and resiliency resources; and

- Expand its rural broadband program to bridge the digital divide and serve the unserved communities in Virginia.

Chapter 4: Generation – Planning Assumptions

The generation planning process begins with the development of a long-term annual peak and energy requirements forecast. Next, existing and approved supply- and demand-side resources are compared with expected load and reserve requirements. This comparison yields the Company's expected future capacity and energy needs to maintain reliable service for its customers over the Study Period. The Company also completes a retirement analysis on certain existing generating resources to determine the feasibility of continuing to maintain and operate those resources. Next, a feasibility screening is conducted to identify a set of future supply-side resources potentially available to the Company, along with their individual characteristics, using input assumptions such as fuel prices, emissions costs, maintenance costs, and resource costs. Additionally, the Company incorporates the cost-benefit screening used to determine demand-side resources that could potentially fit into the Company's resource mix. These potential resources and their associated economics are next incorporated into the PLEXOS model—a utility modeling and resource optimization tool—along with any regulatory requirements (*e.g.*, the requirements in the Virginia RPS Program) and reasonable constraints (*e.g.*, capacity import limits). The Company then develops a set of alternative plans using PLEXOS that represent future paths forward considering the major drivers of future uncertainty. The Company develops these alternative plans in order to test different resource strategies against scenarios that may occur given future market and regulatory uncertainty. The NPV system costs from PLEXOS include the variable costs of all resources (including emissions and fuel), the cost of market purchases, and the fixed costs of future resources.

The Company currently models its system in PLEXOS based on hourly data. This 2023 Plan does not incorporate sub-hourly analysis because of the challenge the Company faced to solve the model with a significantly higher load forecast. Especially for net zero modeling, a single model run could take as long as 18 hours to solve with hourly data. Sub-hourly analysis will require sub-hourly inputs based on historical performance for all resource types that could represent the operating characteristics of those resources for future projections. In addition, the Company must use internal information to establish the adjusted reserve margin and coincidence factor, because PJM does not provide this level of detail. Additionally, sub-hourly pricing would be very difficult to accurately predict and significantly increase the cost of forecasting. Nevertheless, the Company will continue to consider sub-hourly analysis in future Plans and update filings once the required inputs and processes are developed and validated. Sub-hourly analysis would capture the potential benefits from ancillary service markets. For example, sub-hourly analysis would be able to capture the benefits that battery energy storage systems could offer to the regulating services.

In this 2023 Plan, the Company relies on several assumptions for its integrated resource planning process. This chapter discusses these assumptions related to load forecasting, capacity market, commodity prices, construction costs, federal tax credits, new resource, carbon, and modeling. The Company updates its assumptions annually to maintain a current view of relevant markets, the economy, and regulatory drivers.

4.1 Load Forecast

The 2023 Plan presents two load forecasts: (i) the 2023 PJM Derived Load Forecast and (ii) the 2023 Company Load Forecast. The 2023 PJM Derived Load Forecast was used in the development of all Alternative Plans. However, because of the limited nature of the information provided by PJM, as well as reasons described in Section 1.1, ***PJM Load Forecast and Energy Transition Risks***, the Company presents and discusses the 2023 Company Load Forecast as well and presents a sensitivity using the Company Load Forecast. Figures 4.1.1 and 4.1.2 compare these two load forecasts and provide historical peak load and energy. Note that historical data in the charts is not weather normalized and is also not adjusted for retail choice. Both load forecasts include a downward post-model adjustment for energy efficiency and retail choice, as described further in Section 4.1.3, ***Energy Efficiency Adjustment***, and Section 4.1.4, ***Retail Choice Adjustment***, respectively.

Overall, the 2023 PJM Derived Load Forecast anticipates summer peak demand and energy CAGR for the DOM LSE of approximately 2.9% and 4.2%, respectively, over the Planning Period. The 2023 Company Load Forecast anticipates DOM DEV LSE summer peak demand and energy forecast CAGR of 3.2% and 4.2%, respectively.

Figure 4.1.1 - DOM LSE Non-Coincident Peak Load Forecast Comparison

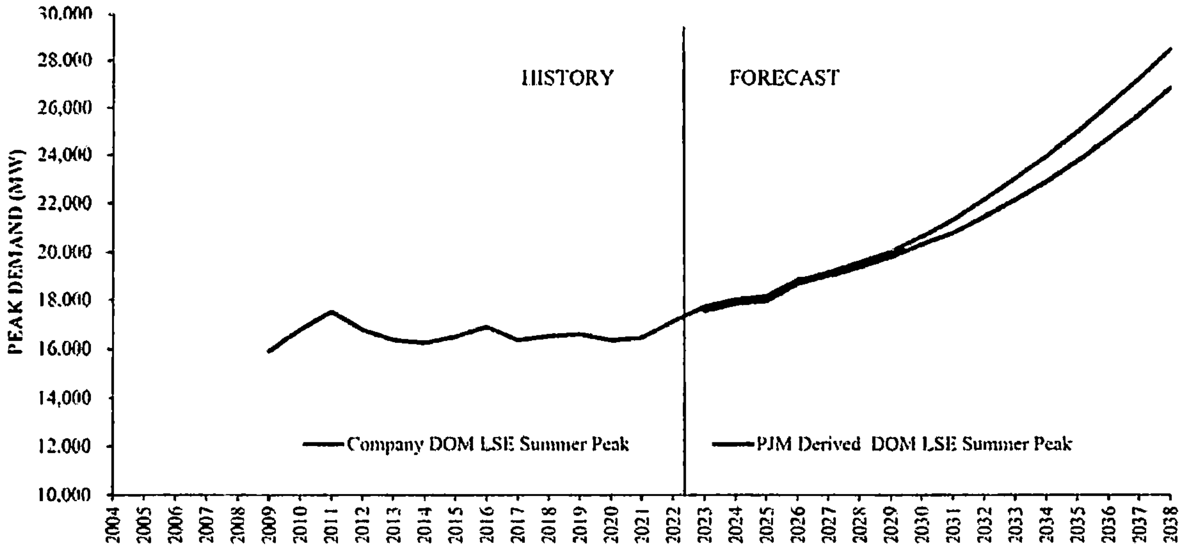
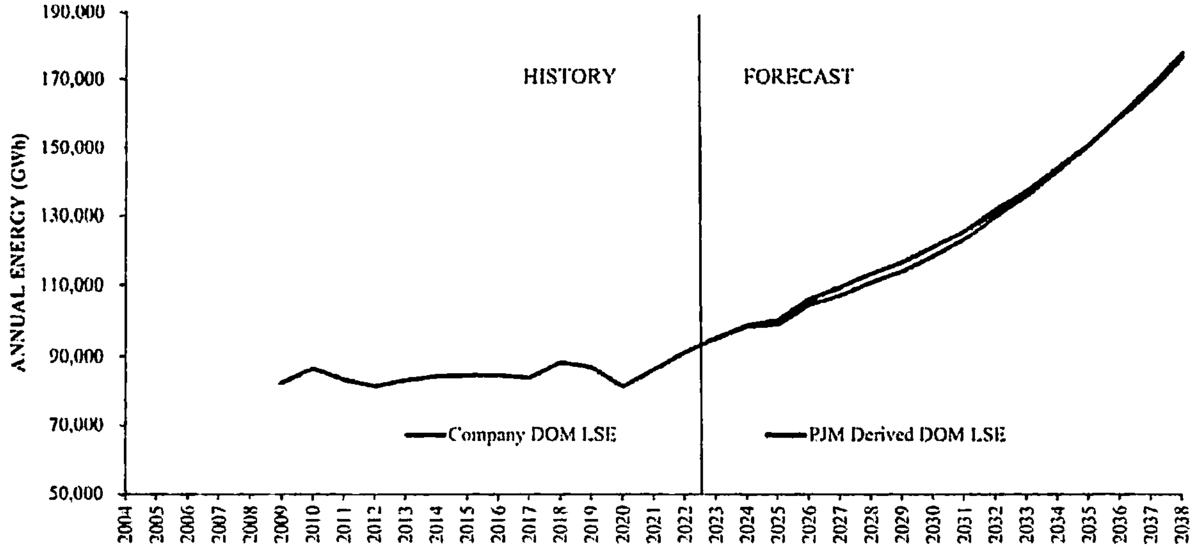


Figure 4.1.2 - DOM LSE Annual Energy Comparison



A 10-year history and 15-year forecast of sales and customer count at the system level, as well as a breakdown at Virginia and North Carolina levels, are provided in Appendices 4A through 4F. Appendix 4G provides a summary of the summer and winter peaks used in the Company Load Forecast. The 3-year actual and 15-year forecast of summer and winter peak, annual energy, DSM peak and energy, and system capacity are shown in Appendix 4H. Appendix 4I provides the reserve margins for a 3-year actual and 15-year forecast, and Appendix 4J provides the 3-year actual and 15-year forecast summer and winter peaks to show seasonal load. Finally, the 3-year historical load for wholesale customers is provided in Appendix 4K. See Appendix 4L for load duration curves for the years 2023, 2028, and 2038 with and without DSM. The information provided in Appendices 4A through 4F and 4K use the Company Load Forecast because PJM does not provide this level of detail.

4.1.1 PJM Derived Load Forecast

The Company utilized the DOM Zone load forecast as published by PJM in its 2023 PJM Load Forecast Report dated January 2023 in the development of all Alternative Plans included in this 2023 Plan. The PJM website (www.PJM.com) contains information on the methods used by PJM in developing this forecast.

To properly use the PJM load forecast in the development of this 2023 Plan, the Company needed to adjust that forecast for modeling purposes. Since PJM does not provide a DOM LSE forecast, the Company first scaled down the PJM DOM Zone coincident peak load forecast and energy forecast, and then extended it. The Company completed this in two parts. First, the Company adjusted the forecast by taking out PJM's DOM Zone data center forecast. This was then adjusted down by utilizing comparable historical DOM LSE to DOM Zone load ratio. The Company then adds back the data center forecast and makes a downward adjustment for retail choice customers and energy efficiency forecasts. This method of scaling down of PJM forecast ensures that the DOM LSE to DOM Zone ratios change in the forecast period appropriately. The Company then extended the scaled-down non-data center forecast based on the 15-year growth rate and extended the DOM LSE-level data center forecast using the Company's forecast of declining annual increases, levelling off at 1% annually in 2043 and beyond. Finally, the Company added these two components together.

Figure 4.1.1.1 presents the 2023 PJM Derived Load forecast. The resulting summer peak demand and energy CAGRs are 2.3% and 3.3%, respectively, between 2023 and 2048. Because PJM considers the DOM Zone to be a summer peaking zone, the Company developed this 2023 Plan using a summer peak to align with PJM's DOM Zone summer coincident peak demand and energy forecast.

Figure 4.1.1.1: 2023 PJM Load Forecast Adjusted to LSE Requirements

Year	DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM Zone Energy (GWh)	DOM LSE Equivalent (GWh)
2023	21,274	16,998	120,495	94,996
2024	22,126	17,266	128,855	98,886
2025	23,058	17,348	136,328	100,205
2026	24,823	18,019	150,796	106,193
2027	26,375	18,341	163,997	109,451
2028	27,906	18,715	177,605	113,308
2029	29,414	19,133	189,774	116,689
2030	30,794	19,622	201,819	121,115
2031	32,276	20,129	214,320	125,692
2032	33,641	20,752	226,951	131,712
2033	34,957	21,415	237,408	137,118
2034	36,221	22,235	247,810	143,789
2035	37,367	23,104	257,503	151,151
2036	38,517	24,059	267,876	159,434
2037	39,690	25,050	276,725	167,093
2038	40,998	26,193	287,188	176,427
2039		27,166		184,689
2040		28,017		192,019
2041		28,653		197,186
2042		29,084		200,851
2043		29,247		202,521
2044		29,396		204,543
2045		29,587		205,902
2046		29,767		207,618
2047		29,954		209,350
2048		30,159		211,450

Note: For years 2039 to 2048, the Company calculated the DOM LSE forecast by adding the scaled-down non-data center forecast extended based on the 15-year growth rate with the DOM LSE-level data center forecast extended using the Company's declining data center growth rate forecast.

Overall, the 2023 PJM Load Forecast (published in January 2023) anticipates that summer peak demand and net energy for the DOM Zone will increase at a CAGR of approximately 4.4% and 6.0%, respectively, between 2023 and 2038. This is markedly different from the 2022 PJM Load Forecast that showed an increase at a CAGR of approximately 2.0% and 2.9%, respectively, between 2022 and 2037. The key drivers for the forecast change are addressed in Section 1.1, ***PJM Load Forecast and Energy Transition Risks***.

4.1.2 Company Load Forecast

The 2023 Plan also includes the Company's internally developed peak demand and energy forecast. The Company ran a sensitivity on Alternative Plan B using this internally developed forecast instead of the PJM Derived Load Forecast, the results of which are shown in Section 2.6, ***Sensitivity Analyses***.

While the Company forecast and 2023 PJM forecast are in general alignment, the Company continues to believe that its forecast is more appropriate to use than PJM's forecast. Because the Company forecasts sales and associated drivers at customer class level, the resulting forecast is better able to capture region-specific load characteristics. As an example, PJM's forecast incorporates DSM reductions, but does not specifically incorporate Company DSM programs or VCEA targets. While the Company attempts to account for VCEA targets in going from PJM Derived forecast, it does so without any regard for DSM already embedded in PJM's original DOM Zone forecast. As another example, the Company has conducted a study to forecast EVs in its service territory, PJM has not been able to conduct such detailed study for each of its load zones. Additionally, since PJM's forecast is prepared in the last quarter of the year, as new information becomes available, the Company's planning process wouldn't be able to incorporate those changes in its base case. This could potentially have a more significant impact as the Company shifts to an October 15 deadline for its Plans using a January PJM load forecast. Finally, there are several complexities encountered in converting the forecast from DOM Zone to DOM LSE that are avoided by directly modeling the Company load, as done in the Company forecast. These are some of the key reasons that support using the Company's load forecast as opposed to PJM's in the long-term planning process.

At a high level, the Company's load forecast is prepared using Company sales data and DOM LSE peak and energy data. The sales data is adjusted by excluding data center sales and adding back retail choice sales. The sales forecast process is described in the subsection titled ***Methodology*** later in this section. The resulting sales forecast is then converted into an energy forecast using a historical regression analysis of energy and sales. This is then followed by post-processing forecast adjustments for data centers, retail choice sales, energy efficiency, behind-the-meter solar and EVs. Finally, peak forecast is derived as described in the subsection titled ***Methodology*** below. Figure 4.1.2.1 presents the 2023 Company Load Forecast. Overall, the Company anticipates DOM LSE summer peak demand and energy forecast CAGRs of 2.6% and 3.4%, respectively, between 2023 and 2048.

The primary refinements that the Company has made to its internal load forecasting methodology since the 2020 Plan are as follows:

- DOM LSE sales, energy, and peak are now modeled directly. In the 2020 Plan, the Company instead modeled the DOM Zone and then derived DOM LSE by utilizing a DOM LSE to DOM Zone ratio.

- DOM LSE peak load is now derived using an hourly model incorporating variables from the Company's Sales Model. Use of an hourly peak model is consistent with PJM's new peak forecast methodology.

- Usage per customer is now modeled directly as opposed to modeling total residential sales. Residential sales are then calculated as usage per customer multiplied by customer count.

Modeling of usage per customer enables the Company to directly capture customer usage trends, housing characteristics, and efficiency trends embedded in historical data.

- Data center sales, energy, and peak demand are now being forecasted as a standalone category for the full forecast term, as opposed to just the first five years of the forecast term, and are being applied to the Company's sales, peak, and energy forecasts as an adjustment. The forecast utilizes a Company-prepared internal data center forecast through 2048.

- The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load.

Figure 4.1.2.1: 2023 Company Load Forecast

Year	DOM LSE Summer Peak Forecast (NCP) (MW)	DOM LSE Energy Forecast (GWh)
2023	17,730	95,423
2024	18,010	98,589
2025	18,157	99,262
2026	18,828	104,669
2027	19,173	107,384
2028	19,597	110,829
2029	20,021	114,070
2030	20,650	118,579
2031	21,346	123,503
2032	22,153	129,998
2033	23,019	135,928
2034	23,963	143,154
2035	24,972	151,046
2036	26,111	159,909
2037	27,220	168,151
2038	28,483	177,740
2039	29,629	186,513
2040	30,541	194,620
2041	31,361	199,934
2042	31,953	204,088
2043	32,230	206,250
2044	32,594	209,102
2045	32,821	210,586
2046	33,141	212,733
2047	33,509	214,902
2048	33,786	217,747

The following paragraphs describe the Company's internal load forecasting process.

Methodology

The Company uses two econometric models with an end-use orientation to forecast sales, energy, and peak demand. The first is a customer class level sales model ("Sales Model") and the second is a system level hourly load model ("Peak and Energy Models"). Both models were estimated over a rolling 15-year historical period as each long-term forecast is developed.

Sales Model

The Sales Model incorporates separate monthly sales equations for residential, non-data center commercial, industrial, public authority, street and traffic lighting, and wholesale customer classes. The sales equation comprises total sales for all customer classes except for residential where a use per customer forecast is developed and is then multiplied by a customer count forecast. The monthly sales equations are specified in a manner that produces estimates of heating load, cooling load, and non-weather sensitive load. In addition to developing a sales forecast, the primary role of the Sales Model is to provide estimates of historical and projected weather sensitive appliance stocks and non-weather sensitive base demand for use as exogenous variables in the Peak and Energy Models.

The residential sales equation also relies on an algorithm that dynamically adjusts forecasted appliance saturation and usage based on historical trends. These historical trends are determined based on 2022 EIA surveys.

Peak and Energy Model

The Company's Energy Model is derived from the sales model using a regression model utilizing a historical relationship between monthly sales and monthly energy.

The Company's Peak Model is comprised of 24 separate equations, one for each hour of the day, with adjusted Company loads as the dependent variable. Prior to estimating the Peak Model equations, historical hourly loads are adjusted by subtracting data center load and adding back historical distributed solar generation and retail choice load. This adjustment is performed in order to ascertain the true load rather than a load that is masked by these factors. The Company's practice is to account for distributed solar and load management programs as supply resources, not as a load modifier.

The Peak Model equations include a non-weather sensitive base demand variable, derived from the estimated aggregate non-weather sensitive base demand components from the Sales Model as well as a detailed specification of weather variables. The weather variables include interactions between both current and lagged values of temperature, humidity, wind speed, sky cover, and precipitation for five weather stations in conjunction with residential heating and cooling appliance stocks. The Peak Model also employs indicator variables to capture monthly, day of week, time of day, holiday, and other seasonal effects, as well as unusual events such as hurricanes that produce widespread outages. Once the peak forecasts are derived, the data center forecast is added back as well as adjustments for distributed solar, retail choice, incremental DSM load, and incremental EV load.

Electric Vehicle Forecast

The Company includes an adjustment to its sales, energy, and peak demand forecast to account for future incremental EV load. Like data centers, a separate EV forecast is developed, and the corresponding incremental sales are added to the appropriate residential or commercial sales forecast as a model post-processing adjustment. The EV forecast was developed by Guidehouse, Inc. Figures 4.1.2.2 and 4.1.2.3 reflect the EV peak and energy forecast, respectively.

Figure 4.1.2.2 – Electric Vehicle Peak Demand Forecast (MW)

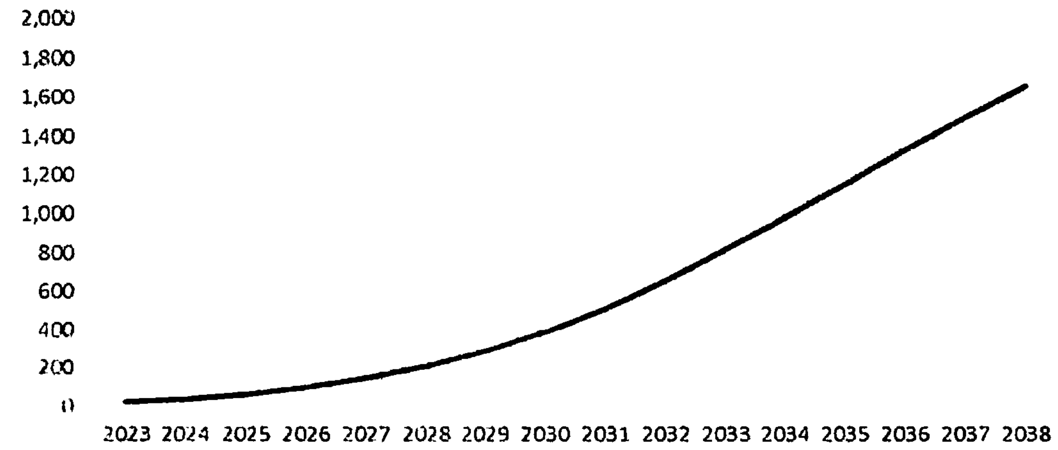
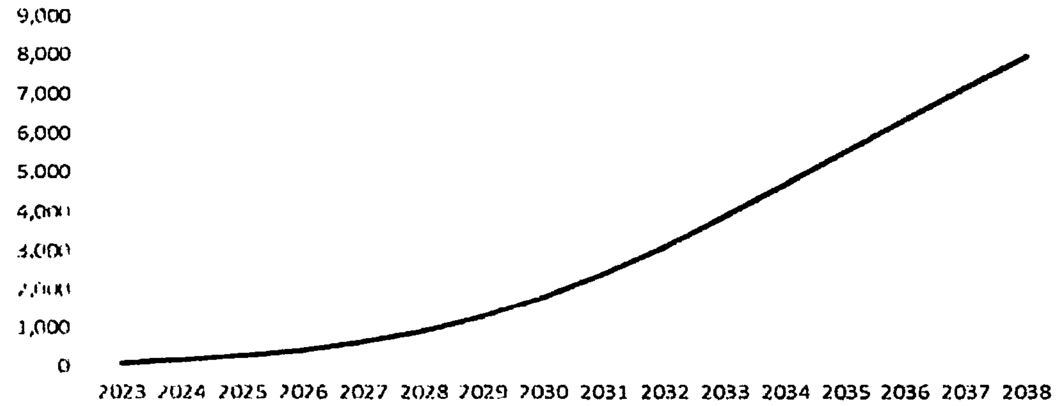


Figure 4.1.2.3 – Electric Vehicle Energy Forecast (GWh)



Economic and Demographic Assumptions

The economic and demographic assumptions that were used in the Company Load Forecast models were supplied by Moody's Analytics ("Moody's"), prepared in October 2022, and are included as Appendix 4M. Figure 4.1.2.4 summarizes the economic variables used to develop the Company's sales forecast.

Figure 4.1.2.4 - Major Assumptions for the Sales and Peak and Energy Models

	2023	2028	Compound Annual Growth Rate (%) 2023 - 2028
Demographic:			
Customers (000)			
Residential	2,468	2,631	1.3%
Commercial	253	265	0.9%
Population (000)	8,708	8,878	0.4%
Economic:			
Employment (000)			
State & Local Government[1]	534	557	0.8%
Manufacturing	238	236	-0.2%
Government[2]	722	745	0.6%
Income ($)			
Per Capita Real Disposable	47,953	53,591	2.2%
Price Index			
Consumer Price (1982-84=100)	304	339	2.2%
VA Gross State Product (GSP)	513	585	2.7%

Note: (1) "State & Local Government" = State (Commonwealth of Virginia) + Local (County + Municipalities)
(2) "Government" = State (Commonwealth of Virginia) + Local (County + Municipalities) + Federal Employment (Non-Military)

Explanatory Variable Comparison

The Company relies on Virginia economic explanatory variable forecasts supplied by third parties in the development of its load forecast. The supplier of these explanatory variable forecasts for the 2023 Company Load Forecast was Moody's; PJM also used explanatory variables from Moody's in the development of its 2023 Load Forecast.

Net Metering Forecast

The net metering forecast process is based on the three-parameter Bass Diffusion Model ("BDM"). The BDM is fitted to actual net metering customer data to determine the three parameters of the BDM, which are the coefficient of innovation, the coefficient of imitation, and the ultimate market potential. The BDM model then determines the net metering customer forecast, which is then translated into energy and peak using historical data.

Wholesale Power Sales

Appendix 4K provides a list of the wholesale power sales contracts with parties to whom the Company has committed to providing full requirement wholesale power sales that are included in the Company Load Forecast.

Results

The results of the Company's forecast are represented in Figure 4.1.2.1. DOM LSE is forecasted to be a summer-peaking system. The all-time summer unrestricted peak demand for the DOM Zone is 21,156 MW and was set in August 2022. The corresponding DOM LSE peak value was

17,131 MW. However, during the recent winter period of 2022/2023, a significant DOM LSE unrestricted peak was set at 17,813 MW. Nevertheless, consistent with the 2023 PJM Forecast for the DOM Zone, the Company forecasts DOM LSE to be summer peaking.

DOM LSE peak and energy requirements are both estimated to grow annually at an approximate CAGR of 3.2% and 4.2%, respectively, throughout the Planning Period.

4.1.3 Energy Efficiency Adjustment

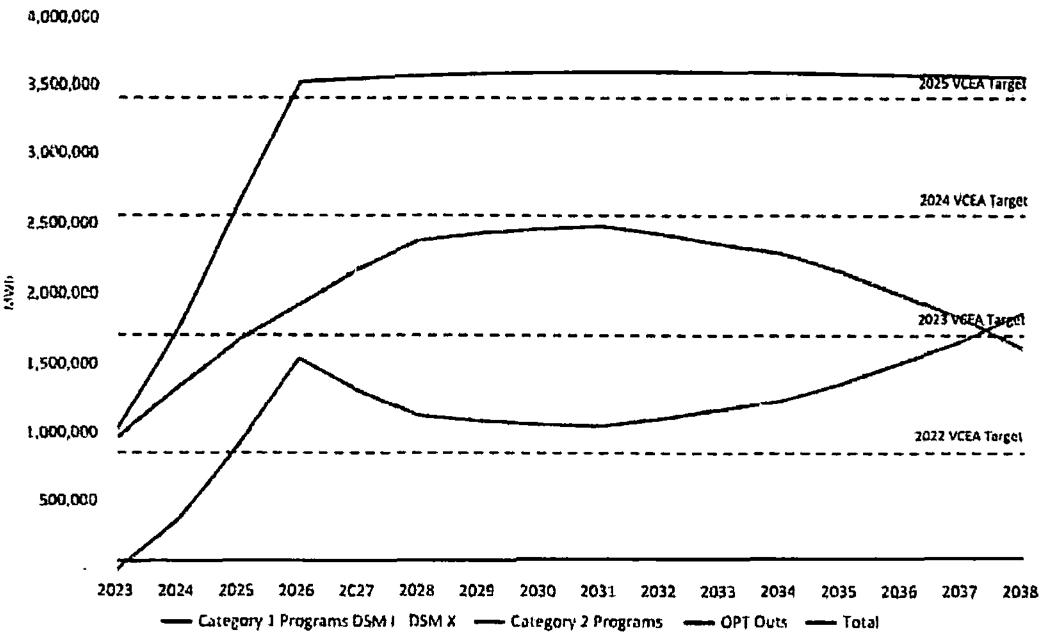
The load forecasts in this 2023 Plan include a downward post-model adjustment for energy efficiency ("EE"). The EE adjustment to the forecasts can be broken down into two distinct categories. The first category ("Category 1 Programs") consists of previously approved EE programs that remain effective (*i.e.*, that are still producing savings), along with programs that were approved by the SCC in Case No. PUR-2021-00247. The second category ("Category 2 Programs" or "generic" EE) represents unidentified EE programs and measures designed to meet legislative directives. Specifically, the generic EE is designed to meet (i) the energy savings targets in the VCEA for 2022 through 2025; (ii) a 5% energy savings target for 2026 and beyond; (iii) the GTSA requirement to propose $870 million in EE programs by 2028; and (iv) at least 15% of EE costs allocated to programs designed to benefit low-income, elderly, or disabled individuals or veterans.

Alternative Plan A is only adjusted for Category 1 Programs. Alternative Plans B through E include the additional adjustment for the Category 2 Program. The Company used the same methodology from the 2022 Update to estimate the Category 2 Program in this 2023 Plan. This methodology uses actual historic costs and savings from the Company's EE programs to determine an average dollar per kWh ("$/kWh") saved price for low-income targeted programs and non-low-income programs and then calculates the estimated projected costs to meet the VCEA energy savings targets at the prescribed levels.

This approach to generic EE is a theoretical assumption used for modeling purposes only. The actual costs and benefits of future EE will be dependent upon many factors, including the ability of future vendors to deliver program savings at the fixed price, customer participation, and the effectiveness of the program to be administered at that price. The Company assumed that the energy efficiency savings target remains constant at 5% in 2026 and beyond based on current projections of the ability of energy efficiency programs to meet these targets, as discussed further in the Company's pending DSM proceeding in Case No. PUR-2022-00210 and based on limitations to the level of energy efficiency savings that can be cost-effectively achieved. That said, the Company has provided sensitivities on Alternative Plan B under different load forecasts to show the effect if the load forecast were to vary for any number of reasons; see Section 2.6, *Sensitivity Analyses*.

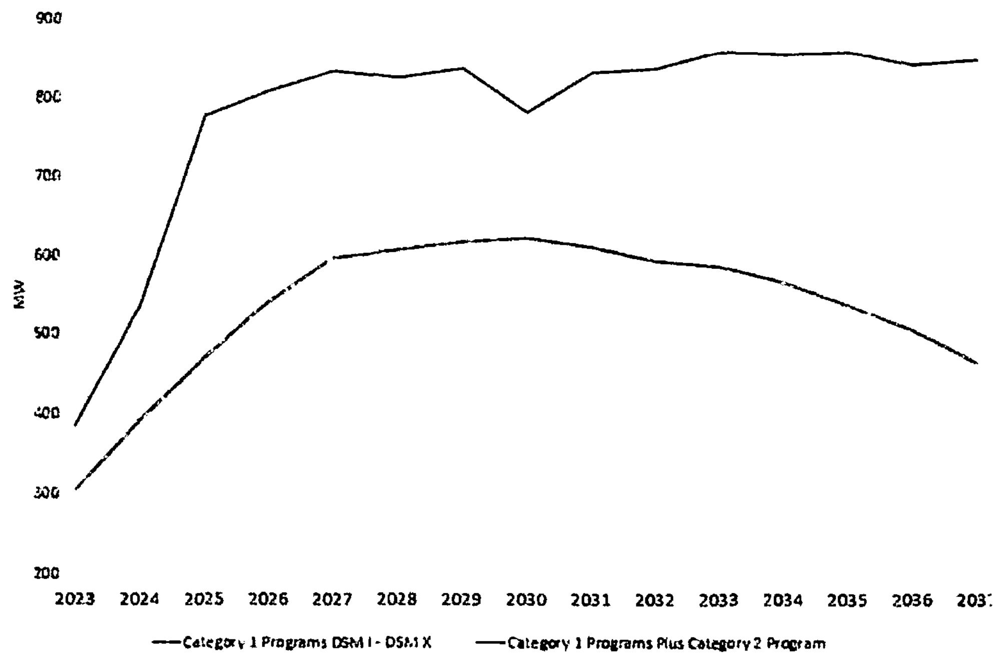
Figures 4.1.3.1 and 4.1.3.2 identify the EE energy and capacity adjustments to the load forecasts used in this 2023 Plan, respectively. Opt-out energy reductions reflected in Figure 4.1.3.1 refers to large general service customers having more than one MW of demand from a single site who have implemented energy efficiency measures at their own expense and have notified the utility and the SCC's Division of Public Utility Regulation of their non-participation in the energy efficiency riders.

Figure 4.1.3.1 – EE Energy Forecast Adjustment



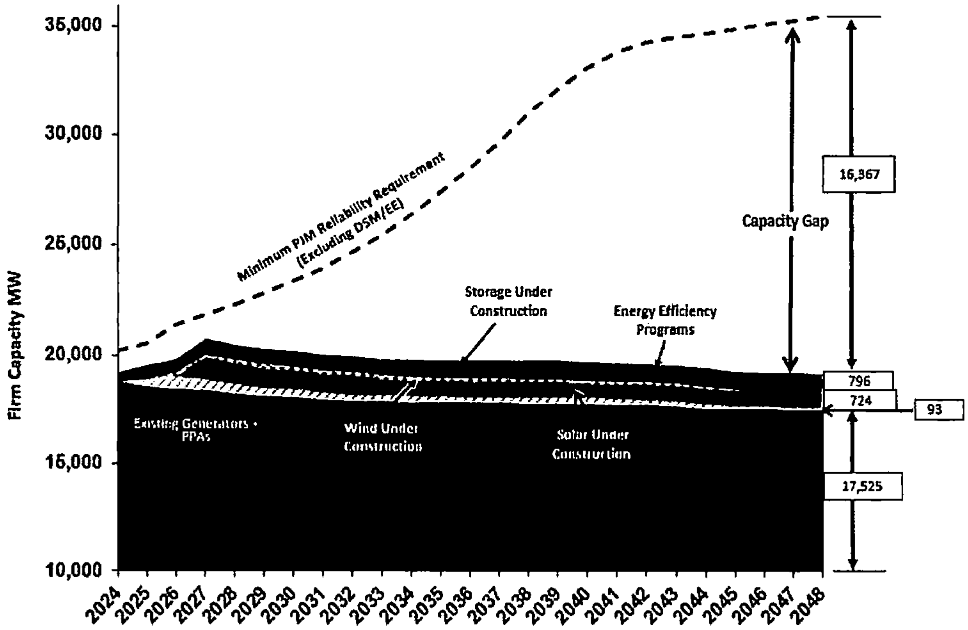
Note: All values shown are at the customer meter and do not include line losses.

Figure 4.1.3.2 – EE Coincident Summer Peak Demand Forecast Adjustment



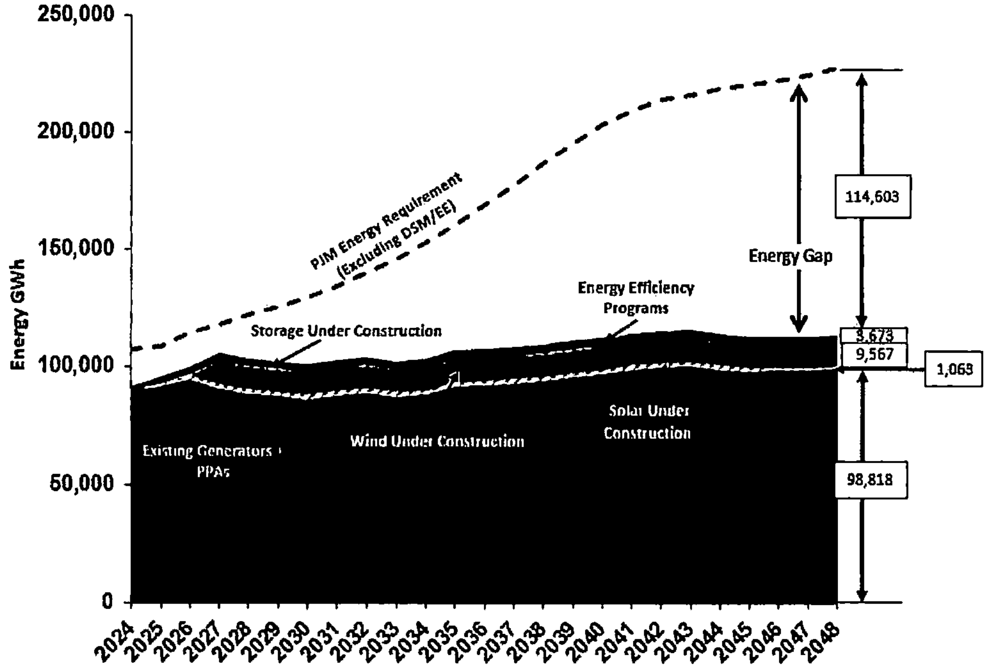
Figures 4.1.3.3 and 4.1.3.4 show the Company's current capacity and energy position with DSM modeled as a supply-side resource using unit retirement assumptions for Alternative Plan B.

Figure 4.1.3.3 - Current Company Plan B Summer Capacity Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency.

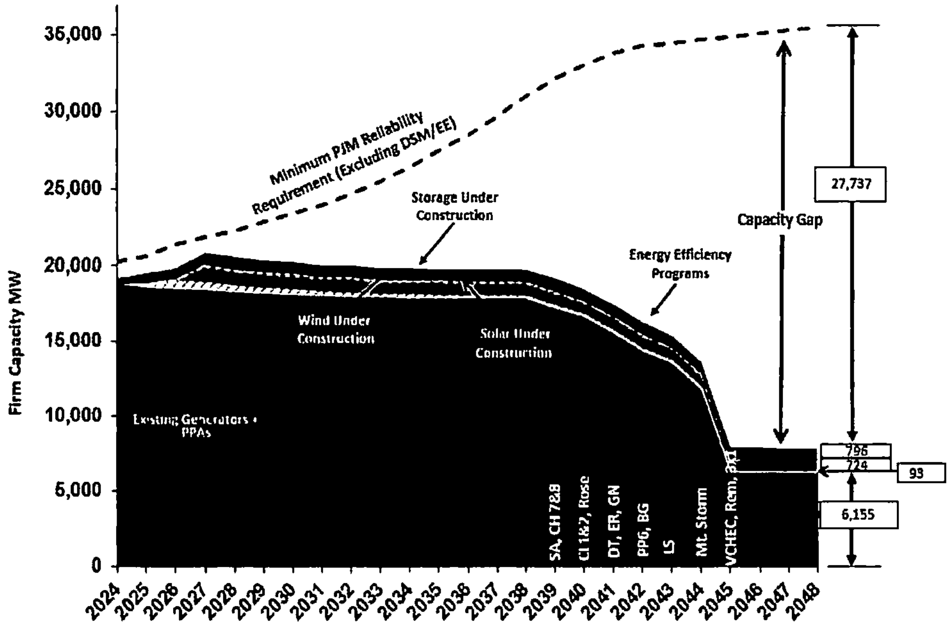
Figure 4.1.3.4 - Current Company Plan B Energy Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency.

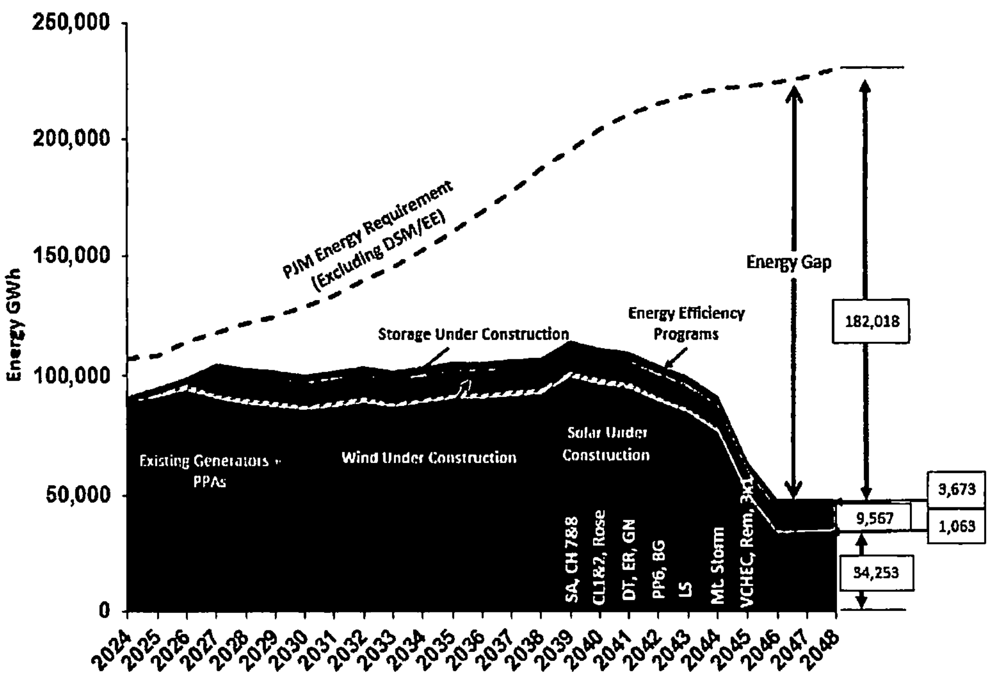
Figures 4.1.3.5 and 4.1.3.6 show the Company's current capacity and energy position with DSM modeled as a supply-side resource using unit retirement assumptions for Alternative Plan B.

Figure 4.1.3.5 - Current Company Plan D Summer Capacity Position (2024 to 2048)



Notes: "PPAs" = power purchase agreements; "DSM" = demand side management; "EE" = energy efficiency; "SA" = South Anna; "CH7&8" = Chesterfield Units 7&8 (gas); "CL1&2" = Clover Units 1 & 2 (coal); "Rose"= Rosemary (oil); "DT" = Darbytown CTs (gas/oil); "ER" = Elizabeth River CTs (gas/oil); "GN" = Gravel Neck CTs (oil); "PP6" = Possum Point 6 (gas); "BG" = Bear Garden (gas); "LS" = Ladysmith CTs (gas/oil); "Mt Storm" = Mount Storm in West Virginia (coal); "VCHEC" = Virginia City Hybrid Energy Center (coal/gob/biomass); "Rem" = Remington (gas); "3x1"= Greensville, Brunswick and Warren (gas).

Figure 4.1.3.6 - Current Company Plan D Energy Position (2024 to 2048)



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4.1.4 Retail Choice Adjustment

The load forecasts in this 2023 Plan include a downward adjustment for customers within the Company's service territory who have chosen to purchase energy and capacity from third-party retail electric suppliers under Va. Code § 56-577 ("Choice Customers"). To develop this forecast the Company first identified the group of current Choice Customers. The Company then determined the annual energy for this set of customers over 2022. Finally, the Company shaped the total energy into hourly intervals using historic Choice Customer interval data.

The summation of each customer's average annual energy and capacity use then formed the starting point for the Choice Customer forecast. The Va. Code §56-577 A 3 customers, whose most recent period demand exceeded five MWs, are also required to provide the Company a 5-year written notice to return to Company service. The Company, to date, has not received such written notice, and has not made any assumptions regarding customers returning to purchase energy and capacity service from the Company. Figure 4.1.4.1 identifies the Choice Customer peak demand and energy forecast adjustment in this 2023 Plan.

Figure 4.1.4.1 – Retail Choice Adjustment

Estimated Retail Choice Sales (MWh)	Estimated Retail Choice Coincident Peak (MW)
5,109,922	820

4.1.5 Data Center Forecast

The Company serves the largest data center market in the world, located in 30 square miles of Loudoun County. There are data centers located in other areas of Virginia, but roughly 80% of the industry is located in Loudoun County. To put this in perspective, the aggregate of the next six largest data center markets in the U.S. is not as big as Loudoun County's market. The data center industry in Virginia achieved a peak metered load of almost 2.8 GW in 2022. This load is roughly 1.5 times the capacity of the Company's North Anna nuclear facility.

Growth Prospects

The data center industry is one of the fastest growing industries worldwide. In the Company's service territory, the industry has grown on average 0.5 GW a year in the last three years. Since 2019, the Company has connected 75 data centers with an eventual capacity of 3 GW. These data centers will ramp up to this capacity over time, so the Company expects this growth to materialize over the next 3 to 5 years. The big drivers of current and future growth include: migration to the cloud as companies outsource information technology functions, smartphone technology and apps, 5G technology, digitization of data, and artificial intelligence.

Types of Data Centers

The Company uses the following segments to describe, track, and forecast the industry:

1. **Cloud** – operating system in the sky (examples: Amazon, Microsoft, Google)
    - Largest segment of the Company's market
    - Cloud providers own servers
2. **Colocation** – "hotel" for other companies (example: Digital Realty)
    - Largest number of companies in the Company's service territory
    - Colocation providers do not own servers
3. **Enterprise** – dedicated facility (examples: Meta, banks)
    - Small number of players
4. **Fiber Interconnection Facility** – routers of the network
    - Small number of players and small size
5. **Bitcoin Miner** – dedicated to cryptocurrency
    - No bitcoin operators in the Company's service territory

Industry Consultant Reports

Several consultant companies publish periodic reports on the data center industry. These reputable companies report only on the colocation segment because the big cloud providers not only build their own facilities, but they also lease the most space from the colocation providers. However, the cloud providers do not publish data on their own facilities. Therefore, the industry reports only include data published in aggregate for the colocation industry; a cloud provider's lease in a

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Forecasting Methodology

The Company has been tracking data and preparing forecasts for a long period of time and has developed a very robust forecast methodology. Figure 4.1.5.1 compares the Company's forecast to actual data center demand for 2020-2022.

Figure 4.1.5.1 – Data Center Industry Peak Billed Demand in MW
Company Service Territory

Forecast Year	Forecast and Results		Variance	% of Variance
	Forecast	Actual	Over/(Under)	To Actual
2020	1,559	1,808	249	14%
2021	2,179	2,302	123	5%
2022*	2,848	2,767	(81)	-3%

* 2022 was the year of the transmission capacity constraint.

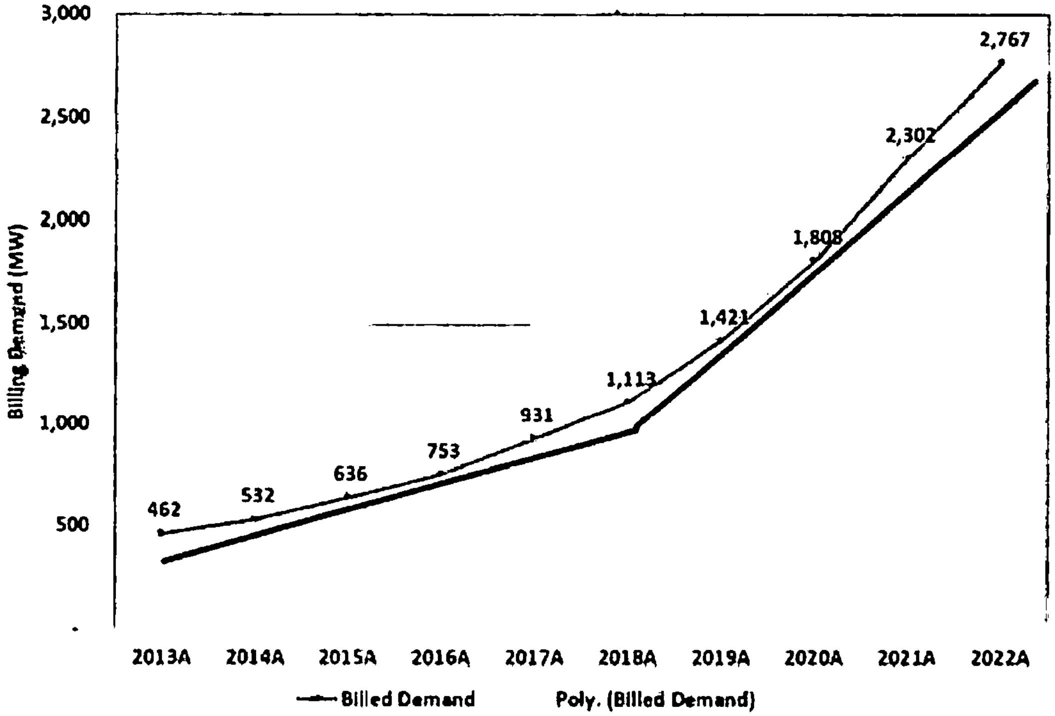
The Company models industry demand growth using the following method:

- Segments the modeling using the eight largest or fastest growing customers and a ninth model consisting of all remaining customers combined into one segment – nine models in total
- Statistically models sales in MWh including lost retail choice sales
- Statistically models demand (MW) using three different approaches
  - Approach 1: linear regression of demand
  - Approach 2: polynomial regression of demand
  - Approach 3: linear regression of sales to demand
- One of these three approaches is selected for each of the nine customer segments based on customer provided intelligence
- Estimate future retail choice conversions (lost MWh sales)
- Develop high, medium, and low demand scenarios
- In total, there are 27 models used to develop the forecast

Historical Growth in Billed Demand

Figure 4.1.5.2 highlights the growth of demand (MW) for the data center industry in the Company's service territory. Note the change in growth that occurred in 2019. Industry growth was relatively flat until 2019 when it increased substantially. The dark black lines on the growth illustrate this change. The dotted line is a polynomial trend line.

Figure 4.1.5.2 – Data Center Historical Growth of Demand in Company Service Territory



Each year, the Company prepares a 15-year forecast of data center load growth. This forecast is consistent with the Company load forecast and is also provided to PJM as requested. Figures 4.1.5.3 and 4.1.5.4 reflect the LSE data center peak and energy forecast, respectively, incorporated into this 2023 Plan.

**Figure 4.1.5.3 – DOM LSE Data Center Peak Demand Forecast (MW)
(Excludes Retail Choice)**

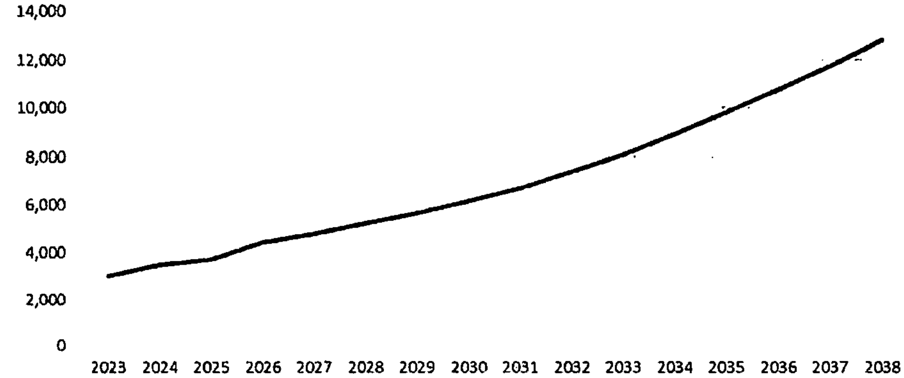
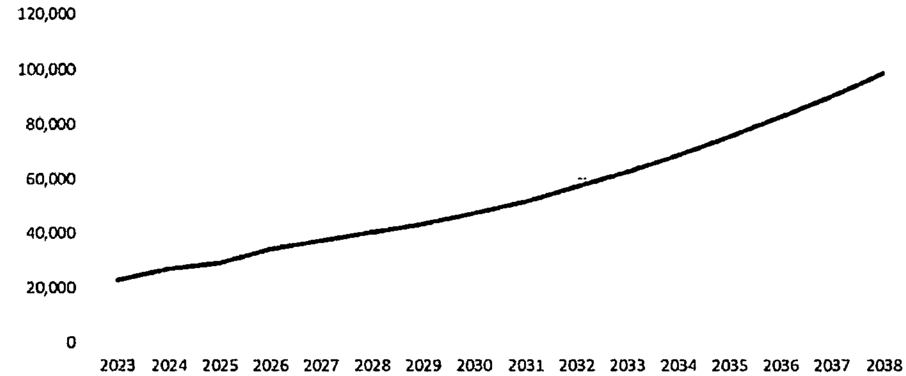


**Figure 4.1.5.4 – DOM LSE Data Center Energy Forecast (GWh)
(Excludes Retail Choice)**



4.2 Capacity Market Assumptions

The Company participates in the PJM capacity planning process to ensure supply of capacity resources for its customer load. As a member of PJM, the Company has the option to buy capacity in order to satisfy the mandated reliability requirements either (i) through the reliability pricing model ("RPM") forward capacity market or (ii) through the fixed resource requirement ("FRR") alternative. PJM's planning years (referred to as "delivery years" for RPM) run from June 1 to May 31. The Company has satisfied its capacity obligation ~~through the RPM auction~~in the capacity market through May 31, 2025.

4.2.1 Short-Term Capacity Planning

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to purchase sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone using its annual load forecast and reserve margin guidelines as inputs. PJM then conducts a capacity auction process for meeting these input requirements up to three years into the future. This auction process includes the base RPM auction as well as subsequent incremental auctions that are held to allow market sellers and PJM to adjust positions for changes such as construction delays or outage assumptions. This auction process determines the clearing reserve margin and the capacity price for each zone for the delivery year that is three years in the future.

PJM had the 2023/2024 base residual auction ("BRA") in June 2022 and the 2024/2025 BRA in December 2022. The 2025/2026 BRA is currently scheduled for June 2023, the 2026/2027 BRA is scheduled for November 2023, and the 2027/2028 BRA is scheduled for May 2024. PJM has proposed delaying the next capacity auction until June 2024, as it attempts to fast-track reliability reforms to the capacity market design. If approved by FERC, subsequent auctions would be held every six months.

Currently, the Company offers its capacity resources, including owned and contracted generation, into its FRR Plan as a generation provider. As a LSE, the Company is obligated to provide sufficient generation to cover its load obligation. The load obligation is calculated using PJM's most current load forecast and planning parameters such as equivalent forced outage rate demand ("EFORd") and reserve margin requirements.

The Company currently satisfies its capacity obligation through the FRR alternative. This alternative allows the Company to self-supply its capacity obligation. Importantly for modeling purposes, however, the modeling is indifferent to whether the Company satisfies its capacity obligation through the RPM auction or through the FRR alternative. Operating under the FRR alternative, the Company would self-supply its capacity obligation. Instead of collecting a capacity revenue stream for generating resources, the Company assumes generating resources would obtain capacity benefit by *avoiding* capacity market purchases. For modeling purposes, the Company would continue to use capacity market forecasts and assume generating resources collect capacity benefits by avoiding capacity purchases under FRR. Further, the modeling is indifferent to whether the Company operates under the FRR alternative because the Company models the forecasted reserve margin at the minimum reserve margin, which is also the obligation under FRR.

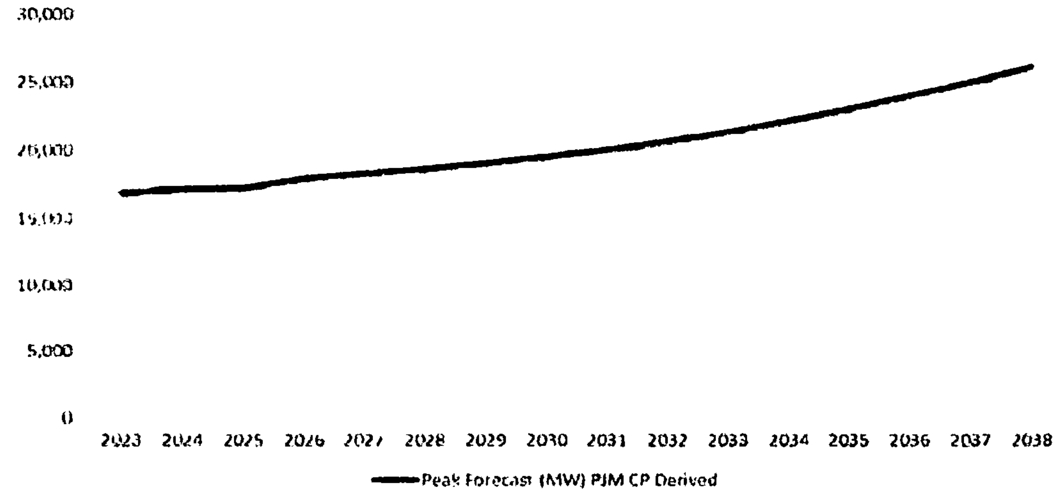
4.2.2 Long-Term Capacity Planning – Reserve Requirements

The Company uses PJM's reserve margin guidelines to determine its long-term capacity requirement. PJM conducts an annual reserve requirement study to determine an adequate level of capacity in its footprint to meet the target level of reliability, measured as a loss of load expectation equivalent to one day of outage in ten years. To satisfy the NERC and Reliability First Corporation Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation, PJM's 2022 Reserve Requirement Study recommended using an installed reserve margin of 14.9% for delivery year 2023/2024, 14.8% for 2024/2025, 14.7% for 2025/2026, and 14.7% for 2026/2027.

PJM develops reserve margin estimates for planning (delivery) years (June to May) rather than calendar years. Because PJM is a summer peaking entity, and because the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer period. For example, the Company uses PJM's 2023/2024 delivery year assumptions for the 2023 calendar year in this 2023 Plan because it represents the expected peak load during the summer of 2023.

The Company makes one assumption when applying the PJM reserve margin to the Company's modeling efforts. Since PJM uses a shorter planning period than the Company (*i.e.*, ten years for PJM rather than 15 years for the Company), the Company uses the most recent PJM Reserve Requirements Study and assumes the reserve margin value for delivery year 2023 would continue throughout the Study Period. Figure 4.2.2.1 shows the adjusted load forecast used in the modeling of Alternative Plans A through E.

Figure 4.2.2.1 – PJM Derived Coincident Peak Load Forecast for DOM LSE



All Alternative Plans were optimized to meet the PJM coincident summer peak load forecast as discussed in Section 4.1.1, ***PJM Derived Load Forecast***, which is labeled as "Minimum PJM Reliability Requirement (Net of DSM/EE)" in Figure 2.1.1, as well as the capacity figures in Appendix 2A.

Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annual updates to load and reserve requirements. Appendix 4H provides a summary of PJM's summer and winter peak load and energy forecast, while Appendix 4I provides a summary of projected PJM reserve margins for summer peak demand.

4.3 Capacity Value Assumptions

Since the fall of 2018, PJM has been developing a probabilistic analysis aimed at valuing the capacity value of renewable energy resources. This approach utilizes a concept called effective load carrying capability ("ELCC"). As defined by PJM, ELCC is a measure of the additional load that a particular generator of interest can supply without a change in reliability. ELCC can also be defined as the equivalent MW of a traditional generator that results in the same reliability outcome that a particular generator of interest (such as an intermittent generator) can provide. The metric of reliability used by PJM is loss-of-load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value (*i.e.*, a higher ELCC) than a resource that delivers the same capacity only during low-risk hours. "High-risk hours" are those hours during which PJM expects the peak demand to occur.

For the purposes of the 2023 Plan, the Company utilized the December 2022 PJM ELCC study to estimate the capacity value of solar, wind, and storage resources, which is the most recently available guidance from PJM. This approach indicated the capacity value of tracking solar is currently 55%, decreasing over time as solar saturation grows. For offshore wind, the capacity value is currently 43%, and decreases over time as offshore wind saturation grows. This is an increase from the value of 40% published in the December 2021 PJM ELCC study. For onshore wind, the class rating is 18%. For energy storage, the starting capacity value is 82% for four-hour systems, and increases after 2026.

PJM currently performs its ELCC calculations at the hourly or daily level. PJM publishes ELCC values for these resource types for a ten-year period through 2032; beyond 2032, the Company used projected ELCC values provided by ICF for the remainder of the Study Period.

On January 25, 2023, PJM stakeholders approved manual and governing document changes for a solution package that addresses the CIRs for ELCC Resources Issue Charge. CIRs are the right to input generation as a capacity resource into the transmission system at the point of interconnection where the facility connects to the PJM transmission system. The new process will begin to apply CIRs in the ELCC studies and performance adjustment calculations by capping the hourly wind and solar outputs at the CIR level starting with the 2025/2026 BRA and may result in an immediate capacity value reduction for wind and solar. These document changes were approved by the FERC in April 2023, and PJM will include the new modeling assumptions in future ELCC studies. For this reason, the Company has not incorporated any assumptions related to potential future changes into the modeling completed for this 2023 Plan.

4.3.1 Capacity Price Forecasting Methodology

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and
- Ancillary services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of supply- and demand-side resources needed to meet predicted peak demand in the future. In a capacity market, utilities or other electricity suppliers are required to purchase adequate resources to meet their customers' demand plus a reserve amount. Suppliers offer supply- or demand-side resources into the capacity market at a price. To the extent the supply offer clears the market, then those capacity resources are obligated to supply energy (or reduce energy in the case of demand-side resources) when dispatched or pay penalty fees.

The RPM is designed to provide financial incentives to attract and maintain sufficient capacity to meet the load demands anticipated by PJM; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. Parallel to the actual market construct, forecasting of long-term capacity prices is based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market energy and ancillary services revenue is not sufficient, then capacity revenues are required to fill this gap.

When forecasting capacity prices over long periods, it is reasonable to assume markets will move toward equilibrium and will provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the new resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower in markets with excess capacity. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note that while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up-and-down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

4.4 Commodity Price Assumptions

The Company utilizes a single source—ICF—to provide multiple scenarios for the commodity price forecasts to ensure consistency in methodologies and assumptions. The key assumptions on market structure and the use of an integrated, internally consistent fundamentals-based modeling methodology remain consistent with those utilized by ICF in prior years' commodity forecasts.

The Company performed the analyses in this 2023 Plan using energy and commodity price forecasts provided by ICF in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, power, emissions (*e.g.*, sulfur oxide ("SOx"), nitrogen oxide ("NOx"), RGGI), and REC prices rely on forward market prices as of February 28, 2023, for the first 18 months of the Study Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity and Federal CO_2 prices are provided by ICF for all years forecasted within this 2023 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM base residual auction up to the 2024/2025 delivery year, then transitioning to the ICF capacity forecast.

In the 2023 Plan, the Company utilized four commodity forecasts:

- Base Case
- High Fuel Price

- Low Fuel Price
- Virginia in RGGI

The Company used the Base Case commodity forecast for all Alternative Plans, which assumes that Virginia exits RGGI before January 1, 2024. The remaining three commodity forecasts were used to run sensitivities, which are described in Section 2.6, ***Sensitivity Analyses***. Appendix 4N provides the annual prices (in nominal dollars) for each commodity price forecast.

As with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this 2023 Plan. History has shown that unforeseen events and events not contemplated five or ten years before their occurrence can result in significant changes in market fundamentals. The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in the 2023 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes.

4.4.1 Base Case Commodity Forecast

The Base Case commodity forecast was developed for the Company to address a future market environment where impacts of the supply chain and commodity price dislocations of the last 24 months are incorporated into projections, natural gas continues to be a dominant marginal source of generation in PJM over the time horizon, tax credits available to renewable and clean technologies from the IRA are incorporated, and enactment of various RPS policies occur, including the VCEA.

Figure 4.4.1.1 provides a comparison of the four commodity price forecasts in this 2023 Plan with the base commodity forecast used in the 2022 Update. See Appendix 4N for additional details of these forecasts, including fuel, allowance, power price forecasts, and the PJM RTO capacity price forecast. See Appendix 4O for delivered fuel prices and primary fuel expense from the PLEXOS model output using the Base Case commodity forecast.

Figure 4.4.1.1 – Fuel, Power, and REC Price Commodity Forecast Comparison

	2023-2037 Average Value (Nominal $)	2024-2038 Average Value (Nominal $)			
Fuel Price	2022 Fed CO_2 Case	2023 Base Case	2023 High Fuel Price	2023 Low Fuel Price	2023 VA in RGGI
Henry Hub Natural Gas ($/MMbtu)	3.90	4.25	6.48	3.62	4.25
Zone 5 Delivered Natural Gas ($/MMbtu)	3.68	3.92	6.15	3.30	3.92
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	73.60	78.54	78.64	78.54	78.54
1% No. 6 Oil ($/MMbtu)	10.95	13.33	15.37	11.88	13.33
Electric and REC Prices					
PJM-DOM On-Peak ($/MWh)	43.91	44.79	61.54	40.01	45.17
PJM-DOM Off-Peak ($/MWh)	36.34	40.64	56.02	36.24	40.87
PJM Tier 1 REC Prices ($/MWh)	13.59	15.87	7.80	20.95	15.85
VA REC Prices[1] ($/MWh)	14.89	17.14	9.06	22.25	17.12
RTO Capacity Prices ($/kW-yr)	51.42	58.88	53.16	59.77	58.80

Note: (1) Reflects ICF forecast data for only rather than a market blend.

4.4.2 High / Low Fuel Price and Virginia in RGGI Commodity Forecasts

The High and Low Fuel Price commodity forecasts utilize high and low natural gas supply scenarios from the EIA to create high and low cases of natural gas fuel prices, as natural gas continues to be a dominant marginal source of generation in PJM over the time horizon in the Base Case.

A change in natural gas prices affects energy prices directly. That is, as natural gas fuel prices increase, energy prices increase. The energy price affects the revenue stream available to renewable energy generators, which in turn results in a change in REC price. In other words, as energy prices increase due to higher fuel prices, REC prices generally decrease as a result of increased renewable build. Similarly, the capacity price is also directly influenced by the marginal sources of energy and is reflective of the net energy compensation requirements. In other words, as revenue available to renewable energy generators increases due to higher fuel prices, capacity prices decrease. Hence, the movement of natural gas prices will impact the resulting power market commodity prices directly and in a consistent manner across high and low scenarios.

In the Base Case and the High and Low Fuel Price commodity forecasts, the CO_2 price forecast incorporates the assumption that Virginia exits RGGI before January 1, 2024, as well as a charge on CO_2 from the U.S. power sector after 2035.

The Virginia in RGGI case is similar to the Base Case, except it assumes that Virginia remains a member of RGGI.

4.4.3 REC Price Forecasting Methodology

ICF's REC price forecasts reflect a weighted average price comprised of multiple RPS sensitivities, including business as usual (latest RPS policies at the time of the forecast), moderate, and aggressive RPS scenarios. Additionally, ICF does not assume REC banking and bases expected renewable builds on the assumption that market participants meet any stated renewable targets.

4.5 Construction Cost Assumptions

Costs to construct new resources are difficult to assess given the current volatility in equipment pricing and supply chains. The Company made assumptions for this 2023 Plan based on best available information at the time of preparation; the Company will continue to monitor construction costs and will update these assumptions in future filings as appropriate.

For this 2023 Plan, the projected solar, onshore wind, and energy storage capital costs are based on the market in Virginia using cost data from Company-developed projects through 2022. Given the currently volatile supply chain environment, and to account for continued market demand challenges, 2023 costs were then held constant through 2026. Beyond 2026, the capital cost increases or decreases for resources were based on the 2022 National Renewable Energy Laboratory ("NREL") annual technology baseline assumptions for the moderate scenario. For SMRs, the Company analyzed capital costs estimates provided by technology vendors and developed a cost estimate based on a generic SMR site in Virginia.

For solar PPA cost assumptions, a market index price was created using the weighted average first year price from conforming PPA bids in the Company's request for proposals ("RFP") for utility-scale solar, onshore wind, and energy storage resources. The market index price was held constant through 2026, and then adjusted based on the NREL moderate scenario.

4.6 Federal Tax Credit Assumptions

Under the Inflation Reduction Act, both PTCs and ITCs have a tiered credit structure that includes a base credit, an increased credit for meeting prevailing wage and apprenticeship requirements, and two additional potential 10% bonus credits if domestic content is used in the project or the facility is located in an energy community. For the modeling completed for this 2023 Plan, the Company assumes that prevailing wage requirements are met and projects that started construction before 2022 and through 2032, receive either the increased tax credit of 30% ITCs or 2.75 ¢/kWh PTCs). The Company has not assumed any bonus credits for generic new units for modeling purposes. Yet the Company is actively pursuing the development of projects in energy communities and expects that bonus tax credits will be available for specific future projects.

The Company modeled utility-scale solar, wind, and new nuclear resources to receive PTCs, and modeled distributed solar and storage resources to receive ITCs. The Company based the tax credits on expected construction timelines and conservatively assumed that units with construction starting after 2032 received no tax credits. These assumptions are for modeling purposes only. For actual projects that the Company pursues, final tax credit decisions will be made on a project-by-project basis as the projects reach commercial operations based on risks and benefits of each tax credit option as well as market conditions and available Internal Revenue Service ("IRS") guidance.

The IRA included many provisions that have the potential to benefit customers, but additional guidance from the IRS will be required for the Company to fully analyze the impact, if any, most of these provisions will have on the Company. The relevant provisions of the Inflation Reduction Act include the following:

- *ITC and PTC Tiered Credit System.* The IRA introduces a tiered credit system applicable for both ITCs and PTCs. The ITCs are broken into a base credit that is 6% of qualified basis. ITCs can then be increased to 30% of qualified basis if the project either (i) meets new wage and apprenticeship requirements; or (ii) satisfies the "begins construction" test prior to January 29, 2023. Similarly, the PTCs are broken into a base credit and increased credit for meeting new wage and apprenticeship requirements. The amount of PTCs then continues to be adjusted annually for inflation.

- *Domestic Content Bonus.* ITCs and PTCs can be further increased by 10% if domestic content is used in the project. This bonus requires that the taxpayer certify that any steel, iron, and a minimum percentage of manufactured product that are part of the facility were produced in the United States.

- *Community-Based Bonuses.* An additional 10% ITC or PTC increase is available if the facility is located in an energy community. An "energy community" is generally defined as a brownfield site; an area with high employment or tax revenues in the coal, oil, or gas industry and a high unemployment rate; or an area in which a coal mine or coal fire electric generation unit has been retired. For solar and wind projects less than five megawatts, additional credits may be applied for if a project is located in a low-income community or on Native American land.

- *Transfer of Credits.* For taxable years beginning after December 31, 2022, taxpayers may elect to transfer certain credits to an unrelated taxpayer for cash. The credit must be transferred by the due date of the tax return for the taxable year in which the credit is generated, and a credit cannot be subsequently transferred. Taxpayers may not transfer existing credit carryforwards.

- *Normalization for Storage.* For stand-alone storage technology with a maximum capacity greater than 500 kW, the IRA permits taxpayers to opt out of the ITC normalization requirement. The election may not be made if it is prohibited by the public utility commission or other similar body which regulates the utility.

- *Nuclear PTC.* For taxable years beginning after December 31, 2023, and before December 31, 2032, electricity produced and sold by an existing nuclear facility to an unrelated person is eligible for a new PTC. This PTC is subject to a gradual phase-out (potentially to $0) to the extent revenues generated by a qualifying facility exceed $25 per MWh.

- *Alternative Minimum Tax.* For taxable years beginning after December 31, 2022, the IRA will impose an alternative minimum tax regime on any corporation which has an average annual adjusted financial statement income for any consecutive three-year period in excess of $1 billion.

In general, the Company selects the federal tax credit option (*i.e.*, ITCs or PTCs) when a new facility is placed in service. The Company also expects the IRA to have a positive benefit for future clean energy investments.

Overall, the Company intends to take all reasonable steps to ensure that its customers receive the full benefits of the Inflation Reduction Act.

4.7 Renewable Energy-Related Assumptions

4.7.1 New Solar Resources

In Alternative Plans A, B, and C, the Company limited the model to selecting a maximum of 900 MW of utility-scale solar per year, which is based on an assumed amount of new solar generation available each year. For Plans D and E, the Company limited the model to selecting a maximum of 900 MW of utility-scale solar per year through 2038 to reflect the maximum total capacity of projects that is expected to be constructed each year due to construction constraints and local permitting. Starting in year 2039, the Company increased the limitation to 1,200 MW per year. Meeting this higher build limit would require improvements in solar technology or possibly out of state solar facilities. For solar resources in Alternative Plan A, the Company allowed the model to select either Company-owned cost-of-service solar or third-party PPAs. For Alternative Plans

B through E, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period in accordance with the Va. Code § 56-585.5.

For all Alternative Plans, the Company assumed a capacity factor for solar resources based on the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia. Specifically, a capacity factor of 22.2% for solar tracking resources and 20.4% for solar fixed tilt resources was generally used, which represent the average capacity factors of Company-owned solar tracking and fixed-tilt facilities in Virginia for the most recent three-year period (*i.e.*, 2020, 2021, and 2022), as required by prior SCC orders. For specific resources with a design capacity factor below the applicable three-year average, the Company modeled that resource at the design capacity factor.

The Company also ran a sensitivity on Alternative Plan B using a projected design capacity factor of 25.2% for future solar resources instead of the three-year historical average capacity factor. The projected design capacity represents an average capacity factor over the life of the facility (*i.e.*, not just three years), considering degradation. The results of that sensitivity can be seen in Section 2.6, ***Sensitivity Analyses.***

4.7.2 New Offshore Wind Resources

In December 2022, the Company received approval of CVOW, which represents nearly 2,600 MW of clean energy. CVOW is thus included in all Alternative Plans in this 2023 Plan. The Company modeled CVOW using a 42% capacity factor, a 30-year life, and updated ELCC capacity values for offshore wind as discussed in Section 4.3, ***Capacity Value Assumptions.*** In all Alternative Plans a second 2,600 MW tranche of offshore wind is available for selection beginning in 2033, which represents the earliest commercial operation date ("COD") for such a project. The same operational modeling assumptions were used for this second offshore wind facility. In Alternative Plans B and D, the Company forced the model to select the second tranche of offshore wind in 2033, to diversify its carbon-free generation sources and meet the Commonwealth's clean energy goals consistent with the timeframe specified in the VCEA and House Bill 2444.

4.7.3 New Onshore Wind Resources

Onshore wind was made available for selection in this 2023 Plan. Like offshore wind, onshore wind requires siting at specific locations to maximize the value for such facilities. The Company made two specific projects under development in Virginia available for selection—a 120 MW project with a net capacity factor of 36.5% and an 80 MW project with a net capacity factor of 42.4%. In addition to these two specific projects, the Company made an additional 60 MW generic onshore wind resource with a capacity factor of 39.5% available for selection once every three years beginning in 2028. While the Company is interested in cost-effective onshore wind projects, the current availability of land suitable for onshore wind construction in Virginia is, and likely will continue to be, a limiting development constraint.

4.7.4 REC-Related Assumptions

For each Alternative Plan, the Company allowed the model to select 100% of RECs for Virginia RPS Program compliance purchased from a PJM REC market through 2024 and assumed that all RECs produced by Company-owned or contracted resources located in Virginia were banked for future use. Beginning in 2025, the Company allowed the model to select 25% of RECs as purchases from a PJM REC market and 5% of RECs for RPS Program compliance as purchases

Part 3

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

Case Number (if already assigned)	PUR-2023-00066
Case Name (if known)	Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.
Document Type	APLA
Document Description Summary	3 of 6 - Integrated Resource Plan of Virginia Electric and Power Company

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from a Virginia REC market for the remainder of the Study Period. Considering the 2023 PJM Load Forecast, growing RPS Program requirements in Virginia and throughout PJM, and a constrained development environment, the Company does not believe the REC markets will support more than 30% of its RPS Program requirements after 2025. The Company took a conservative approach for modeling purposes assuming that the majority of these REC purchases would take place in a lower-priced PJM REC market. See Section 1.7, ***Virginia REC Market***, for additional discussion of the Company's rationale for these assumptions.

REC banking is not possible in PLEXOS, so all REC banking and deficiency payment adjustments are made outside of the model. To account for this, the Company incorporated into the NPVs for each Alternative Plan a credit for excess RECs modeled during banking and a charge for deficiency payments once there is a REC shortage. The Company assumed all RECs generated at Virginia-sited facilities are banked through 2024, ahead of the in-state REC requirement beginning in 2025.

Starting in 2025, RECs are provided by a combination of renewable generation and 30% market purchases. When there is an excess of RECs, the credits are banked for the next year's compliance. Due to the new increased ARB adjustment, REC banking continues until 2033 or 2034 depending on the Alternative Plan. Once there is a deficiency of RECs, customers are charged the deficiency price multiplied by the current year's deficiency volume (in MWhs). By 2039, Plans A, B, and C, have a deficiency of RECs. Plans D and E build enough renewable and zero carbon generation that no deficiency is experienced.

The Company also included its Virginia Schedule 19 PPAs with long-term REC contracts as reductions to the overall RPS Program requirement in all Alternative Plans. The Company identified four solar facilities from which the Company purchases a bundled product comprised of capacity and energy through a Schedule 19 PPA and RECs through a long-term contract. Two of these facilities were included in the behind-the-meter reductions during the PJM load forecast development process; accordingly, the Company did not model these facilities in PLEXOS. Instead, the capacity and energy of these facilities are assumed to be reflected in the 2023 PJM Load Forecast while the RECs were accounted for by reducing the annual Virginia RPS Program requirement by the amount of RECs (as measured by generation) that these units will provide annually. The other two facilities are not behind-the-meter, so were included in the PLEXOS model directly; these facilities are in the "Existing Generation" category on the capacity, energy, and REC charts shown in Section 2.1, ***Capacity, Energy, and REC Positions***.

4.7.5 Renewable Energy Interconnection and Integration Costs

The integration of intermittent renewable energy generation into the electric grid involves multiple considerations. The generator must first be physically interconnected to the electric grid, either at the transmission or distribution level. The developer of a generating facility typically pays the costs to physically interconnect the resource, including any upgrades required near the point of interconnection to assure grid stability. The Company refers to these costs in this 2023 Plan as renewable energy interconnection costs. As increasing volumes of renewable energy generation are interconnected to the grid, additional system-level upgrades must be made by the Company to address grid stability and reliability issues caused by the intermittent nature of these resources. The Company refers to the costs related to these upgrades in this 2023 Plan as renewable energy integration costs. All of these costs are incorporated in the NPV for "Total System Costs" shown in Figure 2.4.1.

In this 2023 Plan, three different categories of solar resources were available in PLEXOS: (i) Company-build solar; (ii) solar PPAs; and (iii) small-scale solar (*i.e.*, less than 3 MW). The Company assumed interconnection cost of $156/kW for Company-build solar and $965/kW for small-scale solar. The Company assumed $0 in interconnection costs for solar PPAs because the PPA price from the developer includes interconnection costs. For wind, the Company assumed the interconnection costs for offshore wind to be $553.73/kW.

In addition to interconnections costs, this 2023 Plan includes three categories of system upgrades costs based on different issues caused by the intermittent nature of renewable energy resources:

Transmission Integration Costs: These costs represent physical enhancements to the transmission system needed to resolve low voltage and thermal conditions caused by integrating significant volumes of solar generation.

Generation Re-dispatch Costs: This category represents costs resulting from real-time variability of load and generator availability compared to day-ahead forecasted load and generator availability.

Regulating Reserves Costs: This category represents ancillary payments the Company must make to resources to ensure that the system can balance intra-day or intra-hour differences in load and generation.

The sections below explain the analyses performed for each of these three categories. While the Company has refined its methods to estimate the renewable energy integration costs compared to prior Plans, more analysis is required in order to fully assess the necessary grid modifications and associated costs of integrating increasing amounts of solar generation.

<u>Transmission Integration Costs</u>

The transmission integration cost was assessed by performing a steady state power flow analysis when a total of 20 GW and 30 GW of solar generation is present on the transmission grid. The analysis was performed based off of PJM's generation interconnection queue to best reflect the interconnection locations, sizes, and behaviors of the solar developers. The resulting power flow violations results were then used to calculate the cost per kW of enhancements to the Company's transmission system.

All Alternative Plans include the addition of significantly more solar generation. Figure 4.6.3.1 shows the incremental integration costs assumed for Company-build solar as additional solar generation is added to the system.

Figure 4.6.3.1 - Total Solar Integration Costs

Solar MW	Total Cost
Up to 20,000	$103.26 per kW
20,000- 30,000	$129.34 per kW